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Recommended Practices for Drilling Geopressured Wells on the Nova Scotian Shelf

CANADIAN PETROLEUM ASSOCIATION

RECOMMENDED PRACTICES FOR DRILLING GEOPRESSURED WELLS ON THE NOVA SCOTIAN SHELF

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RECOMMENDED PRACTICES FOR DRILLING GEOPRESSURED WELLS ON THE NOVA SCOTIAN SHELF

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ACKNOWLEDGEMENT

The following is a list of the membership of the Geopressure Drilling Task Force responsible for the preparation of this report.

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The Task Force wishes to acknowledge the technical assistance provided by staff members of many of the above companies and organizations without whose help this report could not have been produced.

SECTION 1

1.0 FORWARD

These Recommended Practices were developed by a Geopressure Drilling Task Force reporting to the C.P.A. Drilling Committee, and ultimately to the Frontier Division.

The membership of the Task Force consisted of representatives from Canada Oil and Gas Lands Administration and all the offshore operators, at the time, on Canada Frontier Lands.

These Recommended Practices were developed to provide guidance to competent engineers when designing geopressured wells offshore Nova Scotia. The publication is not intended to be a detailed design manual but rather a summary of design and operating concerns that are considered to be applicable to these offshore operations.

The scope of work undertaken by the Task Force was limited to specific topics and the recommendations should be used to supplement good oilfield design and operating practice and not to replace individual engineering judgement.

These Recommended Practices are not intended to form the basis of future government regulations.

It is not intended that any of these guidelines should be construed to exempt the operator from complying with the statutory regulations in force at any time. It remains the Operator's responsibility to meet all regulatory requirements.

SECTION 2

1.0 SCOPE OF WORK

The Geopressure Drilling Task Force limited its scope of work to four topics of investigation.

1. Geopressure Tubular Design

2. Well Control Equipment and Procedures

3. Geopressure Detection

4. Geophysical Pressure Prediction Methods

The recommended practices derived from these investigations are limited in specific application to the Nova Scotian shelf.

The publication is not intended to be an all encompassing summary of applicable technology and must be used in conjunction with applicable regulations, other Industry Recommended Practices and individual operating safety policies and procedures.

The objective of the report preparation was to ensure that the reader would be encouraged to consider a number of relevant engineering design issues and, in the case of the Geopressure Detection Study, would be provided with a large data base of regional well response, to promote an enhanced level of safety inherent in a resulting well design.

SECTION 3

1.0 INTRODUCTION

The Geopressure Drilling Task Force was formed from the C.P.A. Frontier Division Drilling Committee in response to a need for a study group to investigate and consolidate the technology appropriate to offshore Geopressured Well Design, specific to the Nova Scotian shelf.

During the late 1970's and early 1980's several deep, highly pressured gas reservoirs had been discovered during the drilling of exploration wells off the Nova Scotia shelf. Without exception the drilling of these wells presented extreme technical challenges to the Operators and Contractors, both in terms of well design and equipment specifications. Prudent operating procedures were fine tuned to emphasize safety and in many cases exploration objectives were unable to be penetrated because of technical and operational difficulties. The mandate of the Task Force was to develop Recommended Practices that would enhance both the safety and efficiency with which offshore geopressured wells could be drilled. It should be acknowledged that the rapidly developing technology for Frontier Oil and Gas Exploration may render some of these Recommended Practices obsolete in a comparatively short time frame and the reader is urged to maintain an awareness of these developments to ensure state of the art technology is incorporated into well designs whenever appropriate.

These guidelines represent a consensus of industry opinion on the most prudent approach to designing and drilling Scotian Shelf exploration wells. During the course of the discussions which led to the formulation of these guidelines it was frequently the case that alternative approaches to a given problem were identified. In some cases individual operators felt that the approach agreed upon was too stringent or that other approaches would be equally acceptable.

Many of the recommendations and guidelines may have application in areas other than the Nova Scotian shelf, but good judgement will be necessary to determine if some of these stringent requirements would not lead to unnecessary operational limitations and over-design in such operating areas in which quite different circumstances often exist.

SECTION 4

RECOMMENDATIONS FOR FUTURE WORK

1.0 GEOPRESSURE DETECTION

Due to the sensitivity and confidentiality of the geological and reservoir data associated with the exploration wells offshore Nova Scotia, an independent consultant was contracted to perform the study on real time geopressure detection techniques. This study was split into two phases. Phase 1 covered the gathering of data from a short list of priority wells and the presentation of the data in a uniform manner that permitted some general conclusions to be drawn. Phase 2 was to include more detailed engineering analysis of pressure detection data in an effort to develop both analytical and operational techniques that could, in real time, reliably indicate the onset of geopressures.

The information presented in this report represents the efforts from Phase 1 as directly funded by the CPA. Phase 2 of the study was not initiated due to the general industry slowdown and consequent difficulty in justifying significant expenditure at the time. Nevertheless, the Task Force believes that there is considerable scope for further work to complete the needs and requirements of the initial mandate and suggest this work be considered for proposal and perhaps support as a university research project under an Industry Steering Committee.

Such an approach would permit the application of geological, petrophysical, reservoir and engineering skills to the problem at an academic level and may result in some theory that could be incorporated into operational mud logging techniques directly applicable to the field.

Further, it may be appropriate for the CPA to sponsor a similar accumulation of pressure detection data from exploration wells in other areas such as the Beaufort-Mackenzie or Grand Banks if the Nova Scotian data base proves to be of significant value to industry.

2.0 OFFSHORE WELL TESTING

This publication concentrates on recommended practices applicable to the drilling phase of an offshore program. Offshore well testing will be well served by extending the types of design and operating philosophies outlined in this report, into that aspect of the operation, as a study specific to the topic of well testing was not included within this scope of work.

The CPA Drilling Committee may wish to consider setting up a further Industry/COGLA Task Force, similarly structured to the G.D.T.F., to undertake such a study and produce some recommended practices to complement this publication.

SECTION 5

TUBULAR DESIGN GUIDELINES AND RECOMMENDED PRACTICES FOR GEOPRESSURED WELLS ON THE SCOTIAN SHELF

The attached recommendations have been developed to ensure that engineers and operations personnel consider all the factors which may affect the safe design and use of tubulars to be set just above or into geopressures. No attempt has been made to cover all the various aspects considered in a specific casing design. Instead, only those criteria relating directly to pressure control or that have proven themselves to be significant are discussed.

Adoption of the general guidelines by frontier operators will help ensure technically sound design practices are followed without restricting the freedom of a designer to use his own best judgement.

The guidelines have been broken down as follows:

1. Design Philosophy
2. Casing Setting Depths
3. Tubular Design
4. Pressure Tests
5. Materials

It is expected that safe drilling practices will be followed at all times and that these guidelines will only enhance the safety of an operation.

A designer must document the design criteria and rationale used for a well design. This information should be kept in the well file for future reference.

Casing design as specified in COGLA's Drilling Regulations (Sections 63 to 70) must be adhered to and should be treated as the minimum guideline for the tubular design.

1.0 DESIGN PHILOSOPHY

In offshore areas with potential geopressures, a designer's choice of load scenarios (e.g. surface pressures, casing drawdowns for collapse, etc.) should be adequate to reflect both the safety concerns and the potential economic risk. In the absence of a rigorous analysis of these scenarios, generous design factors will be required to cover the unknown.

The application of design factors should be consistent with the number of fully examined conditions and known parameters included in the engineering design. It is reasonable to decrease the design factors if a designer is confident that all service conditions have been fully researched and defined.

Additional safety margins may be prudently required/desired for wells that may be temporarily suspended for environmental or other reasons. Wall thicknesses for example may be increased to account for corrosion over a period of months or years instead of weeks. Casing setting points may have to be adjusted in order to allow a hole section to be cased off before suspension, or to minimize the time necessary to actually suspend the well. No hard safety factors can be defined due to the variety of situations, but consideration should be made for the impact of such events on the well.

2.0 CASING SETTING DEPTHS

Pressure control factors which affect the setting depth of a casing string to be set above or into geopressures include:

a. formation leakoff at previous shoe

b. anticipated pore pressures

c. mud weight in use

d. competency of formation in which the next casing string is to be set

e. minimum detectable pit gain and anticipated pressure profiles during well control

f. choke line pressure drops

g. potential for loss of circulation

h. potential for differential sticking

Other factors which will affect the setting depth of these casing strings are the reliability and quantity of offset data and the experience of operations personnel in the area.

The design value for formation leak-off pressure should be based on the last point on the straight line portion of the plot (see Figure 1). This straight line may be established during the casing pressure test prior to drilling out. As shown on the plot, the fracture propagation pressure may be lower than the leak-off.

3.0 TUBULAR DESIGN

3.1 Definitions

Surface Casing	- first casing to provide full well control capability
Intermediate Casing	- casing designed to provide well control while drilling deeper
Test String	- a string designed to meet production burst criteria for short-term tests without the long term requirement for collapse resistance - in addition, often designed as an intermediate string in order to drill ahead
Production Casing	- a string designed to produce the well over its intended life

3.2 Tubular Design

3.2.1 Burst

The loading case recommended for intermediate casing and liners is a dry gas column to surface from the lesser of the bottom hole pressure (BHP) or the formation leakoff pressure at the setting depth of the string. This is acknowledged to be a conservative design but is warranted due to the high pressures encountered on the Nova Scotia shelf and the potentially severe consequences of a burst failure offshore. In the future, the recommended criteria may be relaxed based on better offset control and experience with time.

Gas heads should be calculated using the Real Gas Law (accounting for pressure and temperature conditions). If the gas composition is unknown, then it would be prudent to use dry gas (methane) for any gas calculations.

As discussed in Section 1, design factors should be based on the number of variables evaluated in the design. Normal burst design factors for all casing strings will range from 1.0 to 1.33.
One of the variables a designer should consider reducing is the external mud gradient in which the casing was set. The gradient may decrease due to solid settling, cement shrinkage or fluid loss to the formation.

For production casing and tubing, the in-service conditions should be included in the design (corrosion, fracturing, artificial lift, stimulation, etc.).

For test strings, it is recommended that the internal casing gradient be based on a tubing leak at surface on top of packer fluid and the external gradient be based on the column of mud in which the casing was run (reduced due to settling, etc.).

The effects of wear, temperature, tension, eccentric tubulars, buoyancy, bending and triaxial stresses should be evaluated and included in the design, if warranted.

Triaxial stresses may be critical for design pressures above 10,000 psi and with thick walled tubulars and should be considered in high pressure designs. At these pressures, the effect of radial and hoop stresses increases substantially for pipe with increased t/d ratios. The combined triaxial stress state may exceed the calculated biaxial stresses by a large margin.

3.2.2 Collapse

Collapse loads will depend on the risk of lost circulation while drilling to the next casing point. In rank wildcat areas the most extreme loading case would be with circulation totally lost to a hydropressured formation in the last foot drilled.

Test strings should be designed for complete evacuation under the test packer due to the potential of complete drawdown in the rat hole. This criterion may be relaxed where drawdown pressures are limited during testing.

Production casing and tubing design should include in-service conditions (e.g. reservoir compaction effects, gas lift, etc.).

The effects of tension, tube eccentricity, wear, temperature and potential salt zones all have to be considered. Casing cemented across salt zones may be subjected to creep loading up to the effective overburden pressure.

With the heavy casing strings required in geopressured wells, the potential of slip crushing while running casing should be checked.

Collapse ratings of tubulars with high, non-API values should be based on the results of testing and statistical derivation on the same grade and size of tube.

Normal casing design safety factor is 1.0 (this is based on internal pressure being zero, external pressure being actual external pressure or pore pressure and API collapse rating as adjusted for biaxial stresses).

3.2.3 Tension

The designer should consider defining the effects of shock and drag loads, bending, buoyancy, thermal variation, potential drawdowns stimulation and pressure testing in determining the axial load.

The mode of connection failure (jump out vs. yield) should be considered in selection of the connection design factor. The risk of loss is significantly less if a connection is rated based on first yield versus a connection rating based on a catastrophic failure due to jump out.

Connections for conductor and surface casing should be structurally designed to support compressive and bending loads of successive casing strings, tubing string, wellhead equipment and the blowout preventors that are set on top of the first housing.

Normal tension design factor:

a. 1.6 for the lesser of pipe body or connection yield.

b. for flush connections it may be appropriate to increase this design factor to account for connection failure (jump out) prior to material yield.

3.2.4 Stability (Buckling)

The following conditions should be evaluated to determine the potential of casing buckling:

a. Stresses due to changing mud weights (inside and out).

b. Wellhead loads.

c. Pressure tests.

d. Change in fluid heights.

e. Temperature variations, etc.

If buckling is a problem, several options are available:

a. Pull more tension at wellhead (surface wellheads only).

b. Increase height of top of cement.

c. Accept potential of buckling after evaluating stresses involved and the potential dogleg magnitude.

On jackups with mud line hangers, stresses induced by conductor pipe bending must be considered in addition to the potential of buckling above the hanger.

3.2.5 Wear

As a result of the long rotating times in geopressured wells, wear must be considered in all tubular strength calculations.

Establishment of a suitable wear rate can be based on offset well data (base line and final casing caliper logs, wear bushing measurements, etc.) or relevant research experience. Factors which will influence wear include mud weight, hole angle, type of hardfacing, etc.

Critical areas are the joints near a subsea wellhead, dog-legs, and kick-off points.

If casing wear is considered a problem near a subsea wellhead, it may be possible to use reduced I.D. flex joint wearbushings, thick wall joints or special hangers to provide sacrifical wear thickness. The benefit of drill pipe rubbers may also be evaluated.

If the use of drill pipe rubbers is considered their impact on well control problems or additional casing wear should be evaluated.

3.3 Downhole Equipment

Downhole equipment should be analyzed using the same load conditions as the casing.

If at all possible, proposed equipment should have a proven history of use in similar environments.

Burst calculations for downhole equipment may be based on actual machining tolerances and material strength formulae instead of API casing criteria. Since the actual dimensions and materials are more closely controlled, the reduced values used in API for wall thickness and yield are generally too conservative.

Where a liner is to be used, the designer should check:

a. Actual dimensions of equipment to be used.

b. Shear pin values - adequate with hydraulics in affect?

c. Hanger, PBR, seal assembly and exterior casing ratings.

d. Tieback movement due to pressure and exterior casing ratings (design and test pressure differentials across the seal assembly may be significant enough to pump seals out of PBR).

e. Wear.

f. Burst loading on exterior casing due to liner weight on slips.

3.4 Cementing

Cementing of geopressured casing and liners should be a major concern of designers since geopressures cause three types of cementing problems

a. Setting casing strings in mud weights close to the previous Formation Leak Off Test (FLOT) and obtaining a high cement top with good lead cement, without losing circulation, is difficult. The risk of swabbing or surging the formation while running casing is also increased.

b. There can be problems associated with the increased geothermal gradient above and within the geopressures. When cementing long liners it may be difficult to obtain a combination of slurries to ensure fast setting at both the top and bottom of the liner.

c. Gas Migration - A cement does not set uniformly and high pressure gas or fluids may channel through the cement due to the hydrostatic pressure not being transmitted down the whole column. This can prevent zonal isolation or even cause leaking liner tops. Specialized slurries are available to help combat this problem.

Reciprocation and/or rotation of the casing is recommended in order to decrease the chance of cement channelling while displacing. Difficulties with subsea equipment may preclude such practices.

4.0 MATERIALS SELECTED FOR CASING, TUBING AND DOWNHOLE EQUIPMENT

4.1 Materials Selection

It is recommended that the materials selected for use in geopressure wells meet or exceed the following guidelines:

Burst (psi)	Minimum Yield (ksi)	Recommended Connections	Quality Assurance Measures
0-2000	40-80	API, Connectors	EMI or magnetic particle on OD and mechanical optical on ID. Hardness verification and UT inspection of weld lines. Thread inspection for thread form, taper, pitch diameter and visual.
2000-5000	40-90	API or Proprietary	Same, Special End Area (SEA) of minimum 18".
5000-10000	80-125	For Burst <8000 psi round LTC or plated BTC in agreement with API 5C3. Additional torque may be used to increase the seal leakage value where the designer has verified that the resultant hoop stresses meet the design factors required. Modified connections (with a teflon ring) or premium metal to metal sealing connections, should be used for Burst >8,000 psi. NOTE: LTC is weak in bending and tension. Not recommended for deviated wells or wells with dog legs.	For t < .500" EMI or UT is acceptable. For t > .500" UT may have to be used due to loss of EMI sensitivity. SEA minimum of 18". Hardness verification and impact toughness tests are required on Grades above 90. Hardness verification tests should be run on all material. Connection performance under loading condition must be verified with physical tests. Mill and field end of connections should be 100% full API inspected. Torque monitoring equipment is recommended for shouldered connections. Make up speed should be limited to low rpm, e.g. 15 rpm or less. Mill end make up is recommended to be in optimum to maximum make up window.
10000+	80-90 T <150°F 95 T <150°F 110-125 T >175°F	Premium Shouldered Connections 150°F < T < 175°F	Recommend full electronagnetic Inspection (EMI). An additional UT inspection can be run dependent on surface conditions and severity of design criteria. Also, a wall thickness check may be advisable. Full material traceability. For Grades above 80 ksi, several samples for each heat shall be taken and four quadrant hardness tests run. Connections shall meet the specifications outlined above.

NOTE

1. When designing for sour service, the recommended NACE Temperatures (T) for the various grades of pipe should be the minimum considering stimulation; well kill operations, etc.

2. SI metric conversion factors:
   PSI x 6.985 E-3 = MPa
   KSI x 6.985 E+00 = kPa
   IN x 2.54 E+00 = Cm
   (°F-32)/1.8 = °C

Consideration for sour service specification tubulars should be given to wells with surface pressures equal to or greater than 10,000 psi depending on the expected concentrations of H_2S that may be encountered. The designer will have to evaluate the consequences of reduced yield strength materials on well design versus the risk of using materials outside the NACE temperature range. Casing grades above 125 ksi are not recommended.

Impact toughness tests should be run at lowest expected temperatures (e.g. -20°C). Where casing is large enough, transverse samples are recommended to obtain conservative values. For toughness requirements, recommended reference API specification for Q-125.

High temperature dope should be used for temperature service of 350°F or greater (minimize amount of metallic compounds).

Requirements for connection performance verification above 5,000 psi service are as follows:

4.1.1 For API Connections

Industry research or in-house testing that supports leak resistance performance for the well loads and fluids.

When using tin or zinc plated couplings, teflon impregnated dope or an equivalent should be used. Tin plated couplings should not be used in high temperature wells.

4.1.2 For Proprietary Threads

Computer analysis and actual test results from the size and weight of casing to be used. Test results may not be extrapolated values from lower test pressures or on another size casing.

4.2 Downhole Equipment

Downhole equipment should meet the same material selection criteria as the casing.

All connections integral to the equipment should meet the same conditions as those of the casing.

It is recommended that float equipment used to float pipe in the hole be tested above the anticipated maximum differential load. At a minimum, the same size and model of float equipment should have been destructive tested under simulated service conditions by the manufacturer.

Tiebacks - For test purposes, tiebacks do not have to be cemented providing calculations performed for various well loading conditions such as perforating, production testing and subsequent well kill operations indicate that the tieback seal assembly will remain in the sealbore. For production purposes, tiebacks should be cemented. The height of cement required will depend on the service conditions.

5.0 CASING/LINER PRESSURE TESTING

5.1 Pressure Test Timing

COGLA Regulations (Section 116 [1]) for the timing of pressure tests of all casing strings run in a geopressured well states ... Casing or liners should be tested prior to drillout; after remedial cementing; once every 1,000 rotating hours or earlier if wear is detected; and prior to production testing.

When drilling in hole sections where geopressures may be encountered, serious consideration should be given to reducing the number of rotating hours prior to retest of the last casing or liner. Factors that should be taken into consideration are the types of bottom hole assemblies in use; the number of trips through the string; hole deviation, etc.

If casing wear is suspected, retesting should be conducted as appropriate. A clue to the presence of wear, which usually occurs in the upper most sections of string, may be detected through visual observations of the condition of wear bushings when retrieved for periodic BOP pressure testing. Another method to detect the presence of wear is to suspend a permanent magnet in the shaker inlet box (possum belly). The magnet will extract wear products (steel fillings or shavings) from the mud system, which may help to indicate the occurrence of downhole wear.

When conducting production tests, casing and liners are not only used as circulating conduits, but also to conduct hydraulic pressure to operate downhole tools in the test string. Pressure integrity is essential to assure tool operation and may also be necessary to ensure validity of test results. Operators should consider performing pressure tests immediately after any plug back in a sequential testing program in order to detect any condition detrimental to casing pressure integrity that may have occurred during operations prior to the current test.

5.2 Pressure Testing Methods

Following the original pre-drillout pressure test, any subsequent re-tests should be conducted by running a packer on drill pipe or testing against bridge or cement plugs (during plugback operations). Dependent on the circumstances, operators may substitute casing caliper or inspection logs for a pressure retest. Use of these tools, however, will not pick up a coupling leak, and can be open to questionable interpretation. If a base log has been run, these tools may be helpful to indicate the extent and magnitude of wear.

5.3 Pressure Testing Liner Laps

Pressure testing of liners is accomplished by imposition of positive surface pressure on the liner including the liner lap. In most cases, such a test provides sufficient proof of wellbore integrity. However, some testing operations in a well could exert a drawdown on the lap creating a condition in the wellbore not previously proven safe. In these cases, where liner laps could be exposed to considerable drawdown, the operator should consider testing for this condition, following a positive pressure test to confirm reasonable integrity.

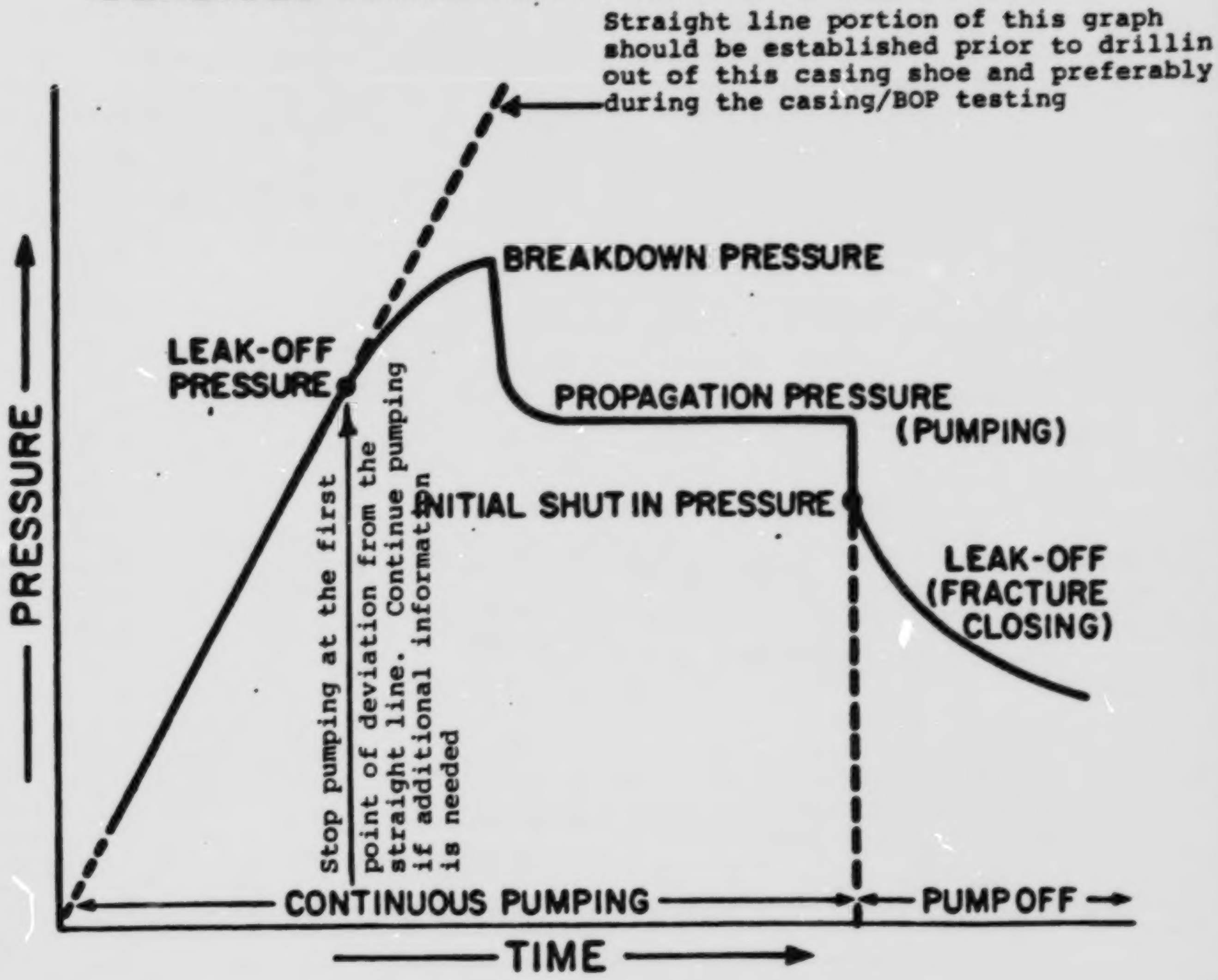
5.4 Test Pressure Magnitude

COGLA Regulations regarding the magnitude of the pressure to be used for casing or liner tests are mandated in Section 116 (2)(b) and (c), and appear to be sufficient for geopressured wells. Tests should be conducted to lesser of the rated working pressure of the BOP stack; 60% of the maximum anticipated fluid pressure in the next section of hold to be drilled or to the calculated fracture pressure at the shoe.Production casing and liners are to be tested to 90% of the maximum reservoir pressure.

Pressure tests of test strings should be performed to a pressure in reasonable excess of that anticipated during the testing operation, i.e. the bottom hole pressure minus a methane gas gradient.

Figure 1

IDEALISED FORMATION FRACTURE BEHAVIOR



NOTE : TESTING BEYOND THE FIRST POINT OF DEVIATION FROM A STRAIGHT LINE MAY CAUSE THE FORMATION TO FRACTURE TO A LOWER PRESSURE (PROPAGATION PRESSURE). THIS FRACTURE MAY OR MAY NOT HEAL AFTER COMPLETION OF THE TEST.

SECTION 6

WELL CONTROL EQUIPMENT AND PROCEDURES

1.0 WELL CONTROL SYSTEM DESIGN

1.1 General

This section has been written to establish guidelines rather than restrictive procedures for operators contemplating carrying out drilling operations in geopressured locations. Material included forms a condensed version of operating procedures adhered to by operators with prior experience drilling in such areas, and is intended to enlighten future operators with lesser experience in geopressure drilling onshore and offshore Canada.

1.2 Blowout Preventer Sizing

1.2.1 Pressure Rating

Blowout preventer pressure rating requirements are specified in the Drilling Regulations. While the regulations are specific, mitigating circumstances may be considered by regulatory bodies should an operator have just cause to appeal their strict enforcement.

Drilling Regulations may not necessarily cover wellhead ratings or other minimum wellhead requirements. The wellhead system, however, should have a sufficient pressure rating to control anticipated maximum formation pressures.

1.2.2 Casing and Bit Programs

The Drilling Regulations do not dictate sizes of casings or drilling bits. The regulations do, however, specify a minimum design criteria for designated casing strings.

1.3 Blowout Preventer Arrangement and Rationale

1.3.1 Diverter System

Diverter Systems are required for bottom - founded offshore units (jack-ups) while drilling at shallow depths before the surface casing has been set. A Diverter System may also be necessary on offshore floating units, but an assessment of the risks associated with gas diversion on the drilling vessel versus sea floor gas breakout is appropriate in this case. Also, the pressure integrity of the marine riser slip joint packing may provide an additional pressure limitation to the system. A diverter system provides a means of directing the flow from shallow formations when the well cannot be closed in because of an unknown or weak casing seat fracture pressure. The system is not designed to shut-in or halt flow from the wellbore, but rather to safely direct flow from the wellbore away from the rig. Typical onshore and offshore diverter installations are shown in Figures 1.1, 1.2A and 1.2B.

Offshore diverter systems should consist of at least one remote controlled annular-type preventer. Also required are remote controlled valves, leading to separate diverter lines. The system may be designed so that one of these valves automatically opens prior to closing the diverter.

1.3.2 Blowout Preventer Stack Design

General Requirements

Blowout preventer stacks are designed to close in a well and contain pressure. Blowout preventer stacks must be designed to perform the following functions:

a. Close off the wellbore around drilling tubulars in order to circulate a kick.

b. Close the wellbore without drilling tubulars in the well followed by circulation into or out of the well.

c. Allow movement of drilling tubulars into or out of the well with pressure on the stack.

Subsea blowout preventer stacks used in floating operations should also be designed for the following:

d. Shearing drill pipe and closing in the well, followed by circulation into or out of the well.

e. Hanging off drill pipe on or below blowout preventers, closing in the well, movement of the drilling unit off and on the location, and then the monitoring and circulation of the well prior to re-establishing drill pipe.

f. One ram or two ram closure on a subsea test tree, closing in the well above the unlatched subsea test tree, movement of the drilling unit off and on the location, and then the monitoring and circulation of the well prior to relatching the subsea test tree.

BOP stacks should provide redundancy/back-up for well control in case of the failure of any one component. Blowout prevention equipment should be designed and rated in accordance with the latest applicable API standards. Specifications, especially minimum impact toughness requirements, should be upgraded for more severe applications. If hydrogen sulfide gas is expected, BOP components and accessories should have metallurgical trim suitable for use with hydrogen sulfide in accordance with current API and NACE requirements.

Subsea BOP Stack Design - Floating Drilling Unit Operations

There are a number of approved subsea blowout preventer stack arrangements in use. For illustration purposes, an example of a typical subsea blowout preventer stack arrangement is as follows (top to bottom):

a. Upper annular preventer
b. Lower marine riser package connector
c. Lower annular preventer
d. Blind/shear ram preventer
e. Side outlet - kill/choke line #1
f. Upper pipe ram preventer
g. Side outlet - kill/choke line #2
h. Middle pipe ram preventer
i. Lower pipe ram preventer
j. side outlet - kill/choke line #1
k. Wellhead connector

This arrangement is illustrated in Figure 1.3. This stack arrangement includes two annular preventers, with one annular preventer intended to back-up the other. A variable ram or smaller diameter pipe ram should be used when well testing or drilling with a tapered drill pipe string.

Pipe rams should be designed such that the heaviest drilling string run into the well can be hung-off from a tool joint landed on the rams. Shear rams should be able to shear full size drill pipe and seal off the wellbore even if the drill pipe stub remains in place.

BOP Stack Design - Land, Island, Jack-Up and Caisson Drilling Unit Operations

COGLA Regulation (106) requires that a diverter system be installed on conductor pipe and conductor casing set for an "onshore" well. Some operators install a BOP system on conductor casing. This allows the designation of the casing to be changed from conductor casing to surface casing providing the formation leak off test (FLOT) indicates sufficient integrity for shut-in, and the conductor casing meets the design requirements for surface casing. (COGLA Regulation (107) requires that a BOP stack be installed on the wellhead when drilling below surface casing.)

The diverter system should be designed to allow components installed between the top flange of the annular preventer and the rig floor to be removed with drill pipe in the hole. This will allow the installation of flanged equipment compatible with the existing BOP stack, if required.

An approved arrangement for a blowout preventer stack installed on a wellhead for drilling below surface casing is as follows (top to bottom):

a. Annular preventer
b. Blind ram preventer
c. Drilling spool c/w 76 mm side outlet
d. Pipe ram preventer
e. Spool
f. Pipe ram preventer
g. Pipe ram
h. Drilling spool c/w 76 mm side outlet

Normally, to shut-in a well, the annular preventer would be closed on drill pipe and the flow directed to the choke manifold via the upper choke line. The pipe rams and lower choke and kill lines provide back-up should pressure integrity be lost in the upper flow line, the upper kill line or the BOP stack above the pipe rams. Three pipe rams provide back-up and capability to vary the ram size. With no drill string in the well, the blind rams should be shut and flow directed through the upper choke line. Some operators locate the lower mud cross between the two lower ram preventers. This does not permit circulation below the lower ram. The lower ram is used to shut the well in of BOP stack repairs are required.

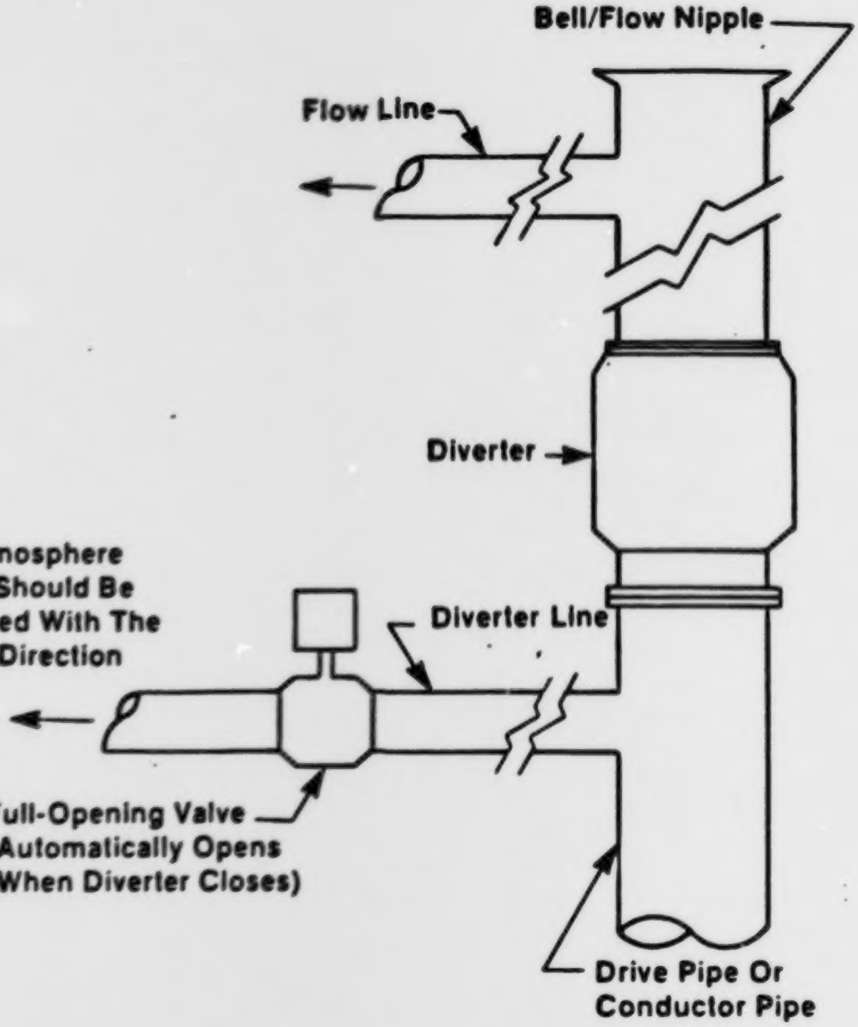

Bell/Flow Nipple
Flow Line
Diverter
Vent Line To Atmosphere Away From Rig Should Be Correctly Oriented With The Prevailing Wind Direction
Diverter Line
Full-Opening Valve (Automatically Opens When Diverter Closes)
Drive Pipe Or Conductor Pipe

Figure 1.1
Typical Diverter System
Surface Installation

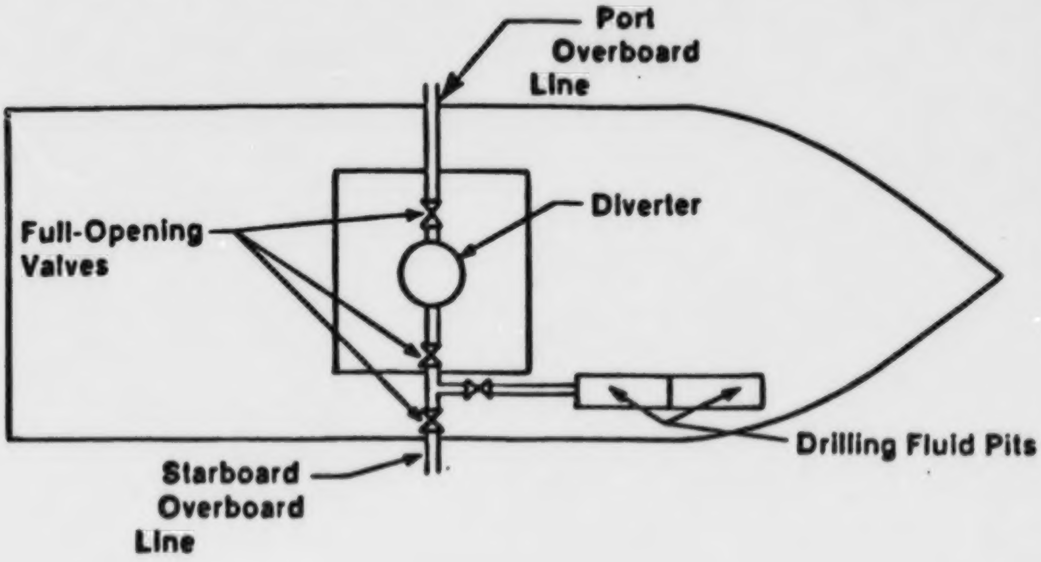

Port Overboard Line
Diverter
Full-Opening Valves
Drilling Fluid Pits
Starboard Overboard Line

Figure 1.2A
Typical Diverter Layout -
Offshore Installation

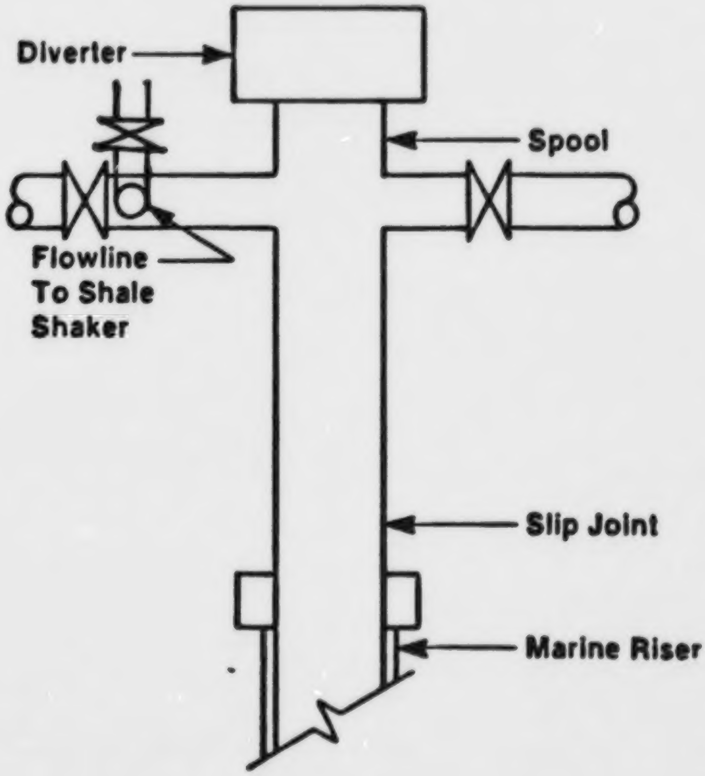

Diverter
Spool
Flowline To Shale Shaker
Slip Joint
Marine Riser

Figure 1.2B
Typical Diverter System -
Offshore Installation

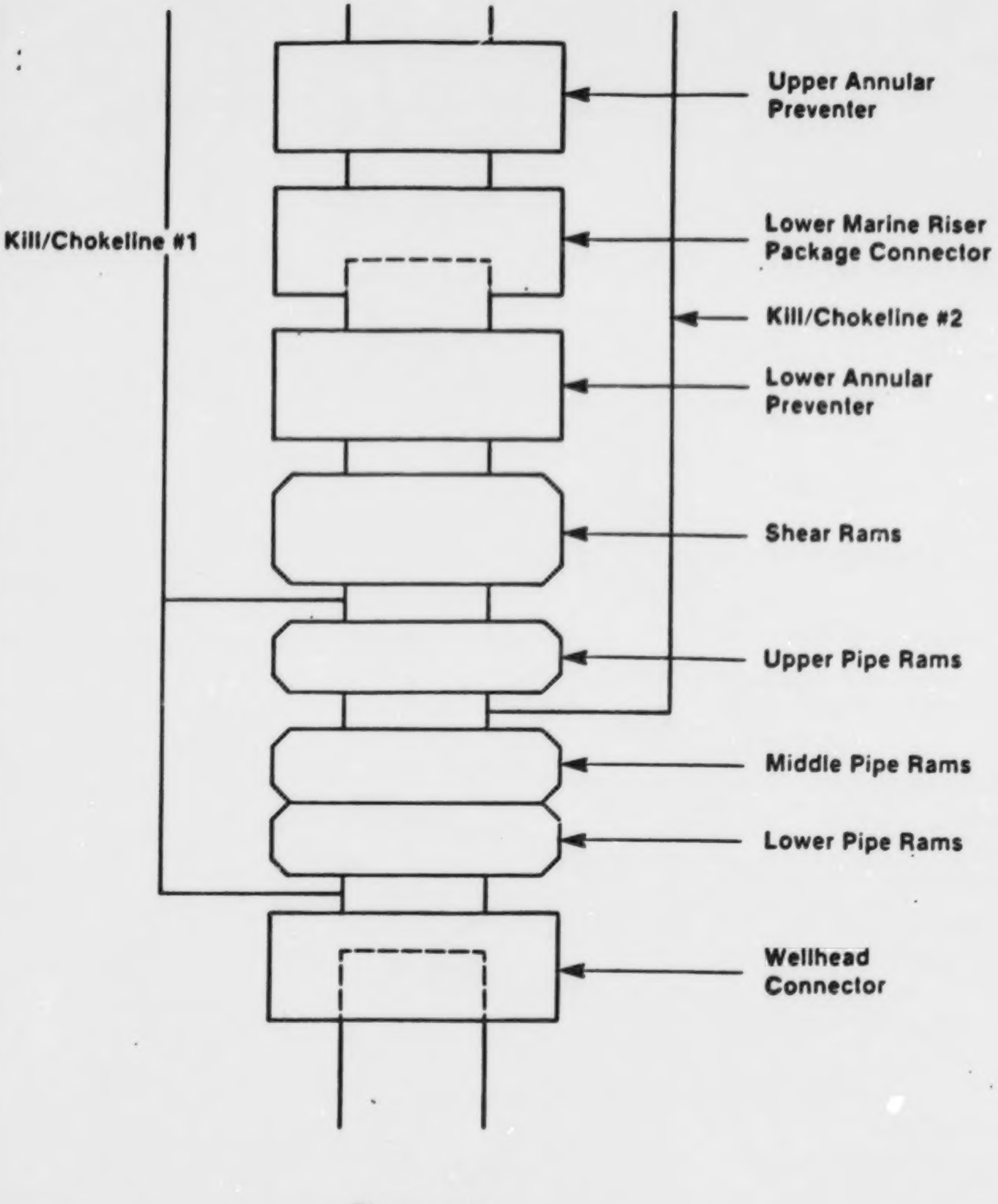

Upper Annular Preventer
Lower Marine Riser Package Connector
Kill/Chokeline #1
Kill/Chokeline #2
Lower Annular Preventer
Shear Rams
Upper Pipe Rams
Middle Pipe Rams
Lower Pipe Rams
Wellhead Connector

Figure 1.3
Typical Sub-Sea BOP Stack Design

1.4 Closing Unit Design

1.4.1 Subsea BOP Stacks - Floating Drilling Unit Operations

Control Systems

Subsea BOP stack control systems must provide individual control for each valve, regulator, connector, and other subsea function.Control systems must be reliable, simple in operation and handling, and provide minimum response time.

Control panels should graphically represent the subsea BOP stack to clearly indicate the function of each control button. Each function's current position should be shown by indicator lights.Flow meters should be located on the control panel to register the volume of power fluid consumed by a specific subsea function. Control panels should be located near the driller's console and at a minimum of one other remote, readily accessible and protected location, as per COGLA Regulations (60).

Hose bundles should ideally be manufactured and supplied in one continuous length to avoid possible leaks and to simplify handling. All hoses should have a minimum working pressure of 21 MPa, and be fire-resistant as per COGLA Regulations (60). Hose reels should permit the operation of subsea latching mechanisms while the reel is in motion, and after the reel has been locked into position, the connection of all additional pilot lines with a single quick connect/disconnect junction box. The control pod serves as a lower terminal for the hose bundle and should house the critical moving parts of the subsea hydraulic control system. Pilot valves and pressure regulators should all be contained within the control pod.

Floating drilling units should be equipped with redundant control systems between the drilling unit and the subsea blowout preventer stack, as per COGLA Regulations (60). Two identical hose bundles and control pods should be installed. If either hose bundle or pod is damaged or severed, the system should allow full control to be switched to the other hose bundle and pod.

Multiplex control systems have the advantage of almost instantaneous signal transmissions, and therefore improved response times at the subsea stack. For this reason multiplex systems are attractive for use in deep water (below 600 m).

Acoustic control systems are generally employed as secondary subsea BOP stack control systems. Present systems have been designed to be used when all conventional means of communication with the subsea stack are inoperative. The acoustic system should be function tested whenever the BOP stack is tested. It is important to function the system in the manner which would be employed in case of emergency, to ensure operation of the system in "real world" conditions. It should be noted that the failure of the acoustic system to function during a routine test may not be of sufficient consequence to merit immediate repair, but knowledge of its operating condition at any point in time is necessary.

Power Systems

Power systems must provide adequate power fluid capacity and pressure for each stack function. Accumulators on floating drilling units should be recharged with nitrogen to 7000 kPa. Accumulators should provide sufficient usable fluid volume (with pumps inoperative) to open and close all the ram preventers and one annular preventer and retain a 50% reserve. A minimum final pressure of 8400 kPa is required to ensure annular preventers remain closed. To meet COGLA Regulations (60), the power system must be capable of (depending upon water depth) closing ram preventers in 30 seconds, any annular preventers smaller than 450 mm bore in 45 seconds, and any other preventer in 60 seconds.

Only separator type accumulator bottles (bladder or guided-float types) should be used on drilling units. Accumulator units should be equipped with both electrically driven triplex pumps and air-powered pumps as charging pumps for the accumulator bottles to provide a secondary source of power fluid as per COGLA Regulations (60). A nitrogen back up system should also be provided. A check valve arrangement must be provided to isolate this system from the accumulator bank. The system should be designed to permit isolation of individual cylinders or banks of cylinders. The nitrogen back up system should be capable of closing an annular and one ram preventer while retaining 8400 kPa in the system. The combination of air and electric pumps should be capable of charging the entire accumulator system to the maximum rated charge pressure in less than 15 minutes. In addition, each recharge pump should be capable of closing an annular preventer and pressuring the control manifold to 8400 kPa in under 2 minutes without accumulator assistance.

The sophisticated subsea BOP systems that are widely used on deep water and geopressure locations are commonly equipped with stack mounted accumulators. These accumulators are mounted on both the lower marine riser package (LMRP) and the main BOP package. They act as "rapid reaction" hydraulic fluid reservoirs which facilitate a quick response to BOP functions, and/or an emergency supply of hydraulic fluid that can be used to operate a limited number of BOP functions in the event that surface accumulator hydraulic fluid cannot be delivered to the BOP's.

In the first instance, the surface control systems have direct access to the fluid stored in the stack-mounted accumulators through surface activated, stack-mounted shuttle valves, which direct the fluid to the various BOP functions. The use of this fluid can greatly reduce the time required for the BOP functions to operate, as it reduces or eliminates the fluid that must be sent to the stack from the surface accumulator through a supply line, which requires approximately 7 seconds per 100 metres of line to achieve a full system operating pressure of 10 MPa.

Many subsea BOP control systems are also fitted with an acoustic back-up system. These systems generally consist of an acoustic transponder/receiver which upon an encoded command can activate electrically powered solenoid valves, which in turn function pilot hydraulic valves which then direct fluid stored in the stack mounted accumulators to a limited number of previously selected BOP functions, usually including shear rams and LMRP disconnect. These systems can be activated from the drilling vessel in the event of a total failure of the surface control system, or from a nearby support ship in the event of an evacuation of the drilling vessel that did not allow sufficient time to activate the necessary BOP functions.

1.4.2 Surface BOP Stacks - Jack-Up Operations

Control Systems

Onshore type BOP stacks employ hydraulic control systems. These systems must maintain constant pressures when stripping pipe through annular preventers. Accumulators must be equipped with several pressure regulating devices so that several stages of pressure can be maintained.

Control panels should graphically represent the BOP stack to clearly indicate the function of each control button. Each function's current position should be shown by indicator lights.Meters should be provided on the control panel to register the volume of power fluid consumed by a given function. Control panels should be provided near the driller's console and at a minimum of one other readily accessible and protected remote location, as per COGLA Regulations (60).

Power Systems

Accumulators should be precharged with nitrogen to 7000 kPa. Accumulators should provide enough usable fluid volume (with pumps inoperative) to open the HCR, close all the ram preventers and the annular preventer, and retain a 50% reserve. A minimum final pressure of 8400 kPa is required to ensure that preventers remain closed. As a minimum, to meet COGLA Regulations (60), the power system must be capable of closing any ram preventer in 30 seconds, any annular preventer smaller than 450 mm bore in 45 seconds, and any other preventer in 60 seconds. Only separator type accumulator bottles (bladder or guided float types) should be used. Accumulator units should be equipped with electrically driven triplex pumps and/or air powered pumps as charging pumps for the accumulator bottles, and to provide a secondary source of power fluid as per COGLA Regulations (60). A nitrogen back-up system should also be provided. A check valve arrangement must be provided to isolate this system from the accumulator bank. The system should be designed to permit isolation of individual cylinders or banks of cylinders. The nitrogen back-up system should be capable of closing the annular preventer, one ram preventer and open the HCR while retaining 8400 kPa in the system. The combination of air and electric pumps should be capable of charging the entire accumulator system to the maximum rated charge pressure in under 15 minutes. All hydraulic control lines must be fire resistant, and the accumulator units must be located in a readily accessible and protected area at least 20 m from the drill floor, as per COGLA Regulations (60). In addition, each recharge pump should be capable of closing an annular preventer and opening the HCR valve, and of pressuring the control manifold to 8400 kPa in under two minutes, without accumulator assistance.

Back-Up Accumulator Power Unit

The accumulator unit may be tied into the cementing unit as a designated back-up, only if the cement unit is independent of the rig power.

1.5 Manifold Design

The choke manifold is designed to control flow of mud and well kick fluids from the annulus during a well control operation.

The choke manifold equipment may be subjected to various severe conditions such as:

a. Hazardous fluids - gas, oil, contaminated mud and sour fluid.

b. High line stresses caused by high pressure upstream of the choke and erosion due to severe velocity changes downstream.

c. Choke line expansion or contraction due to varying flow temperatures.

d. Formation of gas hydrates as wet gas flow is restricted through the chokes.

e. Fluid freezing problems when drilling in sub-freezing environments.

f. Material in the return fluids such as sand, shale, pipe scale and rubber which can cause plugging of the chokes and erosion at bends in the lines and downstream of the chokes.

Although the choke manifold is not routinely used during drilling operations, the potential service conditions show the importance of having the system properly designed, installed and tested prior to taking a kick. Experience has shown that well control problems are minimized when kicks can be circulated without delay and without interruption for equipment repairs.

1.5.1 Choke Manifold

Purpose

If the hydrostatic head of the drilling fluid is insufficient to control subsurface pressure, formation fluids will flow into the well given sufficient formation permeability. To maintain well control, back pressure is applied by routing the returns through adjustable chokes until the well flow condition is corrected.

Design Guidelines

The following guidelines should be considered with designing a choke manifold for drilling a geopressured well for example of an approved choke manifolds for offshore drilling is illustrated in Figure 1.4.

a. The choke manifold pressure rating, up to the first valve downstream of the choke, must equal or exceed the pressure rating of the blowout preventer stack.

b. The nominal diameter of all lines and valves comprising the choke manifold should be equal to or greater than 76 mm.

c. All piping and valves should have the same uniform inner diameter.

d. Minimum of one line straight through the choke manifold. This line is commonly referred to as the "Gut Line".

e. Manifolding must be provided to direct flow to the chokes.

f. The entire choke manifold system must be secured against movement during use, while still allowing for thermal expansion.

g. The header arrangement on the choke manifold must be such that if any one of the chokes cuts out due to the flow of mud, gas or cuttings, another can be used without having to shutdown the well control operation.

h. Valving must be provided such that a cut-out part (e.g. a line, valve or choke) can be isolated and replaced while flowing through another section of the manifold.

i. The choke manifold must be equipped with an automatic choke and the control for the automatic choke should be on or near the drill floor.

The control panel should contain accurate drill pipe and casing pressure gauges, pump stroke rate and count, choke control lever, and choke position indicator. An air operated hydraulic pump should be located in the control panel to furnish hydraulic power for operating the choke. In the event the air operated hydraulic pump fails, the choke should be manually operated with a hand pump on the control panel.

j. Wear sleeves or flow couplings must be installed on each choke to minimize erosion due to turbulence.

k. All components of the choke manifold such as valves, chokes, crosses and flanges shall be fabricated, and tested in accordance with API Spec. 6A - Wellhead Equipment. NACE certification must be obtained for all components in sour service applications.

l. Field welding must be avoided on alloy steels except in extreme emergencies. Appropriate heat treatment and welding procedures must be used in those emergency cases.

m. All connections must be flanged except downstream of the last valve where a threaded connection can be used.

n. Flanged, 90° targeted, or block tees should be used to protect against erosion on all bends.

o. An accurate high pressure gauge should be installed on the manifold system to read casing pressures. Accurate low pressure gauges should also be available.

p. There must be the capability to read casing pressure with every path through the manifold.

q. In addition to the usual mud pump pressure gauges required with the rig (on pump and stand pipe) two remote type, 21,000 kPa with 70 kPa calibration, gauges should be available for installation in the manifold system. There should also be available a 1,400 kPa conventional pressure gauge with stand pipe fittings for detection of low drill pipe pressures.

r. All components exposed to freezing conditions should be protected, either by heating (no open flame), draining and blowing dry, or by filling with a non-freezing fluid.

s. The choke manifold should be located on or near the rig floor.

t. If the choke manifold is not located on the rig floor then a system of communication must be installed from the manifold to the rig floor.

u. Where the choke manifold is an enclosed area, the area must be properly ventilated and must have at least two exits.

v. Every component of the choke manifold must be easily accessible.

w. The valve handles on the choke manifold should be marked "open" or "closed" to indicate their normal position. A diagram indicating which valves are normally open and closed should be posted near the manifold.

Subsea BOP Installations - Special Considerations

a. A minimum of four chokes is required, two of which must be power operated.

b. The cement unit or mud pumps must be tied into the choke manifold to permit kill operations down either the choke or kill line.

c. Where the cement unit is inadequate for providing high pressure kill pumping, a dedicated kill pump of adequate capacity should be manifolded into the system.

d. Check valves must be installed between the choke manifold and the cement unit or mud pumps to prevent back pressure on the pumps.

e. Accurate high pressure gauges should be installed on the manifold system to read choke and kill line pressures. Accurate low pressure gauges should also be available.

f. The choke manifold must be capable of permitting flow to the overboard lines, mud tanks or degassers.

g. The choke manifolds should be fitted with a drain line.

1.5.2 Choke and Kill Lines

Purpose

The kill line system provides a means of pumping into the wellbore when the normal method of circulating down through the drill pipe cannot be employed. The choke line system provides a means for directing the flow from the well annulus to the choke manifold when the well is shut-in in the event of a well control problem.

On subsea BOP installations, choke and kill lines are connected through the choke manifold to permit pumping or flowing through either line.

Design Guidelines

The following design guidelines are recommended for both surface and subsea BOP stack systems. Guidelines specially for surface and subsea systems are listed separately.

a. Have a pressure rating equal to or greater than the pressure rating of the blowout preventers.

b. Be made of steel or high pressure flexible hose covered with fire resistant material.

c. Have an nominal diameter of at least 76 mm.

d. Be designed so as to minimize the number of changes in direction in the line (in order to minimize friction loss through the line).

e. Flanged, 90° targeted, or block tees should be used to protect against erosion on all bends.

f. All choke and kill lines must be protected from freezing (insulated, heated or filled with glycol) to ensure system operation in the event of an emergency. Consideration must be given to the low temperature properties of materials used in installations exposed to unusually low temperatures.

g. All valves must comply with API Specification 6A.

h. Every connection of the choke and kill lines to the BOP stack must be double valved with full opening valves.

i. The kill line must not be used as a fill up line. Routine use of the kill line could result in erosion of the lines and valves thus reducing their effectiveness in an emergency.

j. Testing, inspection and general maintenance of choke manifold components should be performed on the same schedule as employed for the blowout preventers in use.

Subsea BOP Installations - Special Considerations

a. Each choke and kill line must have two full opening valves adjacent to the preventers. These valves must be hydraulically operated and be "fail-safe" in the closed position.

b. A minimum of two lines and three connections to the BOP stack are required.

c. The fail-safe valves must be pressure compensated for deep water applications.

d. Flexible connections required for choke and kill lines both at the top and bottom of the marine riser, must have a pressure rating equalling or exceeding the rated working pressure of the ram preventers.

e. Selection of the top connection must include consideration of criteria such as relative movement between vessel and riser, environment, type and temperature of fluids handled, pressure integrity, service life and ease of connect/disconnect operations.

f. Bottom flexible connections (circumventing the flexible joint) have the same requirements as the top connection but are even more critical due to their relative inaccessibility and the environmental conditions under which they must operate. For deeper water operations, particular consideration must be given to internal/external pressure integrity and reliability.

Surface BOP Installations - Special Considerations

a. A hydraulically controlled gate valve (HRC) and manually operated gate valve must be installed on the upper choke line at the BOP stack.

b. The choke line must be tied into the BOP stack in two locations.

c. The kill line should be tied into the BOP stack in two locations.

d. A check valve must be installed in the kill line.

1.5.3 Diverter and Flare Lines

Purpose

a. "Diverter" means a device fitted on a wellhead or marine riser for the purpose of directing the flow of fluids away from the drill floor in an emergency.

b. "Flare Line" means a line fitted downstream of the choke manifold for the purpose of directing hydrocarbons to a flare pit or burner boom.

Diverter System Design Recommendations

A Diverter System should be used while drilling at shallow depths before the surface casing has been set. The system provides a means of directing flow from shallow formations when the well cannot be closed in because of an unknown or weak casing seat fracture pressure. The system is not designed to shut-in or halt flow from the wellbore, but rather safely to direct flow from the wellbore away from the rig.

Diverter systems should consist of at least one remote controlled annular-type preventer. Also required are remote controlled valves, leading to separate diverter lines. The system may be designed so that one of these valves automatically opens prior to closing the diverter. The diverter lines should be designed to vent in two different directions to accommodate downwind diversion. Diverter valves and lines should be free of restrictions to prevent bridging of the flow stream and excessive erosion. Diverter lines should be designed to provide a straight flow path, but if this is not practical should be turned with long sweeps and secured against movement. Overboard diverter lines should terminate at least 3 m beyond a MODU's structure.

Diverter systems should have a minimum rated working pressure of 3500 kPa. Diverter lines should be sized to minimize back-pressure on the well. A common line size for offshore applications is 305 mm. During diverter operations, rig power is often reduced or shutdown to reduce possible ignition sources. Therefore, the diverter element control system should include a positive shutoff device to maintain closing pressure on the diverter element in the event of power loss. It is also advisable to equip the diverter control system with a separate remote pressure supply to allow control should the primary system deplete.

Flare Line Design

There should be at least two flare lines, directed to different quadrants. Lines should be sized to minimize back pressure. It is recommended that lines be at least 76 mm nominal diameter, and be securely tied down.

Offshore drilling units are often equipped with an additional overboard line or lines from the choke manifold, to permit the overboard discharge of well fluids which are not amenable to flaring.

An additional line is normally provided which permits flow to be directed from the choke manifold to the atmospheric degasser, which is, in turn, equipped with a derrick vent line.

1.5.4 Mud Gas Separator

Purpose

The mud gas separator is vital component of well control equipment. It is installed downstream of the choke manifold on or near the mud tanks. Gas entrained drilling fluid from the well is circulated through the mud gas separator. The gas is separated from the drilling fluid and vented. The useable drilling fluid is returned to the active system.

Ineffective use of the mud gas separator can cause gasified mud to be circulated back down the hole further complicating the well control problem. When a gas kick is properly shut-in and circulated out, the mud gas separator must be capable of removing most of the gas.

Types

There are two basic types of mud gas separators:

a. Open bottom
b. Closed body

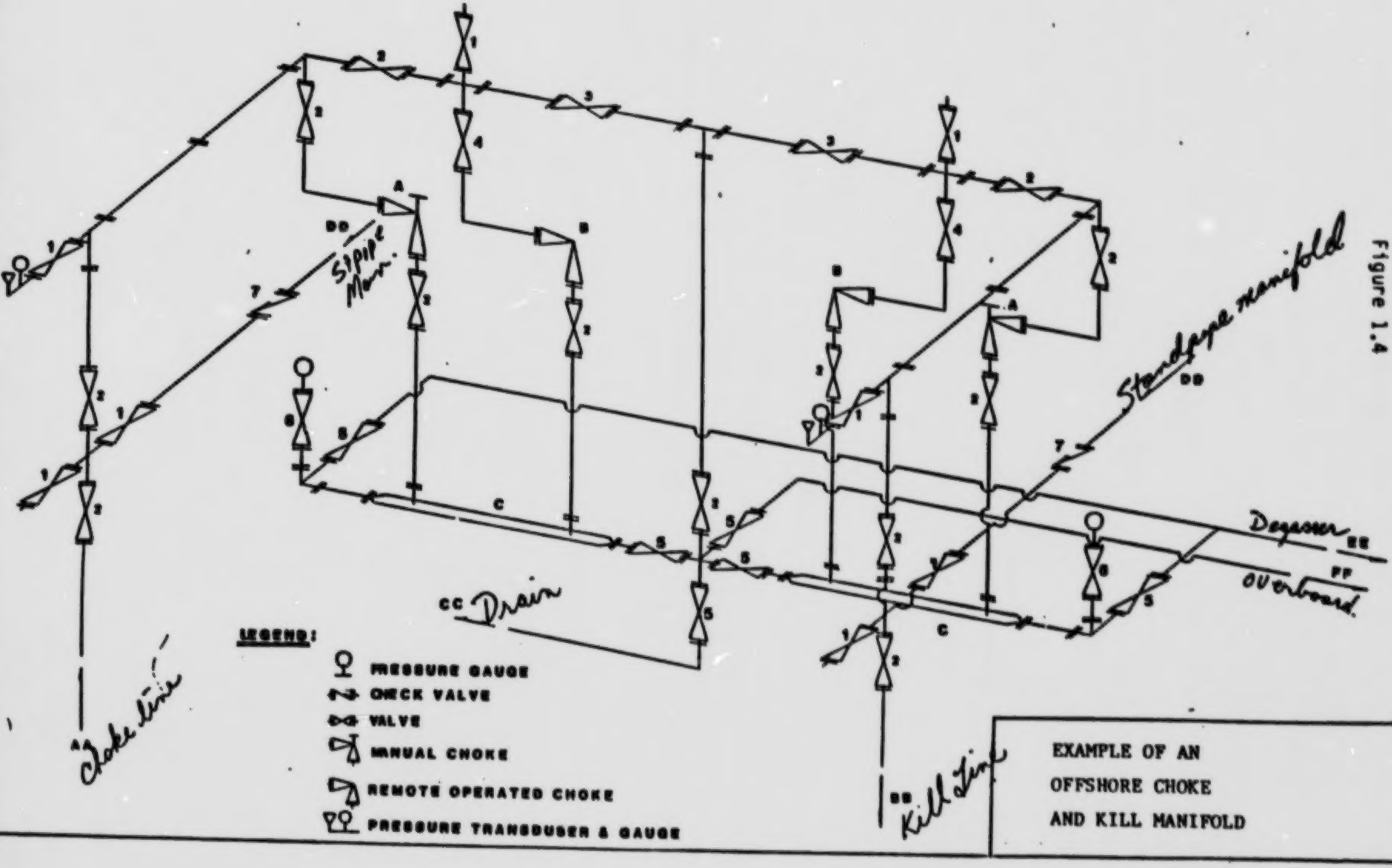
The open bottom separator (commonly called a "poor-boy" degasser) is standard equipment on most rigs. These separators are very simple and do not require control valves in either the inlet or discharge lines.

The efficiency of closed body separators can be improved through the use of vacuum pump to remove the gas. These separators are very effective when properly designed and well maintained.

Design Guidelines

An excellent study of atmospheric mud gas separators has been conducted by the Canadian Petroleum Association. This study entitled "Guidelines and Specifications for Designing Mud Gas Separators" was published by the C.P.A. in June 1984. Refer to this publication for detailed design guidelines.

Figure 1.4


Choke line
AA
DD
S/pipe Man.
A
B
C
CC Drain
Standpipe manifold
DD
Degasser EE
PP
Overboard.
BB
Kill Line
1
2
3
4
5
6
7
LEGEND:
PRESSURE GAUGE
CHECK VALVE
VALVE
MANUAL CHOKE
REMOTE OPERATED CHOKE
PRESSURE TRANSDUCER & GAUGE

EXAMPLE OF AN
OFFSHORE CHOKE
AND KILL MANIFOLD

MANIFOLD DESCRIPTION

Valves

1. 52 mm x 103,000 kPa Gate Valve
2. 78 mm x 103,000 kPa Gate Valve
3. 78 mm x 103,000 kPa Gate Valve, Remote Operated
4. 78 mm x 103,000 kPa Gate Valve, with a 6:1 or 1:1 Gear Reducer
5. 78 mm x 70,000 kPa Gate Valve
6. 52 mm x 70,000 kPa Gate Valve
7. 52 mm x 103,000 kPa Check Valve

Inlets and Outlets

AA. 78 mm x 103,000 kPa Choke Line

BB. 78 mm x 103,000 kPa Kill Line

CC. 78 mm Manifold Drain Line

DD. 52 mm x 103,000 kPa Frac Unit, Cementing Unit and Mud Pump Inlet Line

EE. 108 mm Poorboy Degasser Line

FF. 78 mm Overboard Diverter Line

Chokes and Miscellaneous

A. 78 mm x 103,000 kPa Manual Adjustable Drilling Choke

B. 52 mm x 103,000 kPa Power Operated Choke

C. 305 mm x 70,000 kPa O.D. Buffer Tank

1.6 Auxiliary Equipment

This section discusses equipment used to control pressures inside the drill string, temporarily suspend wells while drilling, and aid in kick detection while tripping.

1.6.1 Kelly Cocks

The kelly cock is a full opening valve placed between the kelly and the swivel or, if it is a lower kelly cock, between the kelly and the drill pipe. It allows the swivel and kelly hose to be isolated from well pressure and, in the case of a lower kelly cock, to stand back the kelly with pressure on the drill pipe.

They should meet the following design criteria:

a. Working pressure compatible with the BOP stack.

b. An internal diameter equivalent to the kelly or drill pipe for the lower kelly cock, and large enough to drop an inside BOP dart through.

c. Mechanical strength sufficient to pick up on the drill pipe.

d. Outside diameter so that it can be stripped through the annular preventer.

The operating wrench for the kelly cocks must be kept on the rig floor in an accessible place, and its location must be known by all crew members.

Kelly cocks should be frequently maintained and tested to ensure they will work properly when required. Pressure testing should be done at the same time as the rest of the blowout prevention system and must be done from the bottom end of the valve.

1.6.2 Stabbing Valves

A stabbing valve is a full opening valve which is stabbed on the drill pipe if the well flows up the drill pipe or collars while the kelly is disconnected when making a connection or during a trip. Stabbing valves, are designed to thread into the drill pipe or collars and can be rapidly closed to shut-in the string.The kelly may then be "stabbed" onto the drill string and control procedures may be initiated.

Stabbing valves are required for the various thread types and sizes of pipe or collars that may be in the drill string. Change over subs may be used to eliminate the need for numerous valves. The appropriate sub should be installed on the valve so that it can be stabbed quickly when required. It is recommended that the stabbing valve be equipped with handles such that two men can stab and make up the valve without having to lean over the pipe. These handles should be removable.

The stabbing valve should be kept on the rig floor in a full open position so that it can be stabbed quickly when required. It should not be closed until it is made up tightly to the drill string. The operating handle should be stored with the valve.

Stabbing valves must be pressure tested at the same frequency as the rest of the BOP equipment and the test pressure should be applied from the bottom end. They should be kept clean, dry and must be lubricated and maintained frequently so that they will close easily when required.

1.6.3 Inside Blowout Preventer

An internal or inside blowout preventer is like a check valve, fluid can be pumped through the device but it is designed to automatically close when pressurized from below. An inside BOP is required for stripping drill pipe into the well during well control operations.

The dart is one of the more widely used tools. It is pumped down the drill pipe and latches into a special reduced bore sub.Depending on the type and size of tool, the dart may be recovered by wire line. The sub should be placed as low in the drill string as possible. Internal diameter restrictions of the sub and drill collars and downhole tools must be considered when positioning the sub in the drill string.

The drill pipe float valve serves essentially the same purpose as the dart valve. Normally, these valves are placed in the bit sub. If used above the bit sub they may cause problems running wire line tools. Since they are one way valves, they may cause greater surge pressures when running in the hole and reduced trip speeds may be required. Special procedures are required to measure drill pipe pressure if a non-ported float valve is in the drill string.

1.6.4 Packers

Commonly referred to as "Hurricane Packers", packers and "storm chokes" are normally used in any situation on a movable drilling unit where a positive sealing/shut-off method is required. The most common use is to effect a temporary well suspension in the event that a drilling unit has to leave a location due to weather or ice hazard. Once the hazard has passed and drilling operations may be resumed, the packer and safety valve combination can be safely removed.

The packer is normally placed thirty or more metres below the wellhead. While in place it should have the capability to hang a drill string which may have been pulled to just within the last casing. The packer should be designed to withstand a greater differential pressure than the surrounding casing, be easily retrievable and pressure tested from above.

The ability to monitor pressure below the packer when the well has been re-entered is essential. For this reason, a back pressure valve assembly should be part of the temporary suspension package. Tensile rating should be equal to packer tensile rating. Before latching into the valve assembly, precautions should be taken to monitor and control pressures at surface.

1.6.5 Trip Tanks

While tripping out of the hole, the volume of the mud required to keep the hole full as the drill string is pulled out must be monitored. This permits early detection of swabbing or flowing.The most accurate method for measuring fill volumes is the use of a trip tank.

The trip tank can be any tank in which the mud volume can accurately be measured within 0.05 to 0.1 m^3. It should be a small (5 to 10 m^3 capacity), easy to measure tank, calibrated with volume marks, and tied into the flow line. The hole fill pump should be run continuously to avoid the confusion caused by the lines draining and refilling when the pump is operated intermittently.

The trip sheet must be used when making a trip out of the hole. A competent person should be assigned to fill in the trip sheet and monitor the mechanical trip tank indicator. The mud logging unit should also monitor the trip tank with their PVT devices.

2.0 BLOWOUT PREVENTER SYSTEM TESTING

2.1 General

The integrity and reliability of the blowout preventer stack, choke manifold, auxiliary equipment and all other related components can only be assured by a safe, set, and routine test procedure. COGLA Regulations (Nov. 1980) dictate the pressure testing and the function testing requirements of the major components of the blowout preventer system. Operators may have their own policy but the COGLA Regulations should be treated as the minimum. Other components of the BOP system should be tested as shown in the following sections.

A written procedure, complete with diagrams showing individual rams, fail safe valves, manifold valves and piping are helpful aids to determine an effective and time saving pressure test program. All manifold valves must be pressure tested in a sequence to ensure that all valves hold pressure. The testing sequence must also ensure that the undirectional manifold and BOP rams are not pressured on the wrong side. A report (of which an example is shown in Tables 2.1 and 2.2) showing items tested, test pressures, function volumes/times and other relevant data should be filled out for each test and witnessed by the operator's representative. It should also include any repairs done on the components, special tests done, etc.

Prior to applying pressure, the system to be tested should be circulated to minimize air entrapment. The next step in the test sequence is the low pressure test to 1500 kPa. The pressure may then be brought up in 10,000 kPa stages to the maximum test pressure to be applied. A successful test is indicated by no pressure decline over 5 minutes or less than 5% decline over 15 minutes.

A low volume, high pressure pump is required; sometimes the cement unit is used for the tests. The test fluid should be a low viscosity solids free fluid. In cold weather conditions, the test fluid should be freeze depressed and all lines should be displaced to this fluid when testing is finished. Accurate pressure and volume recorders should be used during the tests, for both BOP control fluids and test fluids. Volumes and pressures recorded should be compared to manufacturers' specifications and to previous tests to identify any abnormalities.

Table 2.1 : BOP STACK TEST

WELL: ____________ RIG: ____________ DATE: ____________
[illegible]: ____________ [illegible]: ____________ LAST BOP TEST: ____________

WELL INFORMATION:

HOLE:	SIZE:	DEPTH:		MUD WT:		
CASING:	SIZE:	DEPTH:	GR:	WT:	P_B:	P_C:
DP:	SIZE:	CONN:	GR:	WT:	P_B:	P_C:

BLOW OUT PREVENTORS:

UNIT	MAKE	SIZE	PRESSURE RATING (kPa)	FUNCTION [illegible] (sec)	
				CLOSE	OPEN
ANNULAR-UPPER					
ANNULAR-LOWER					
SHEAR RAMS					
PIPE-TOP (1)					
PIPE-MIDDLE (2)					
PIPE-LOWER (3)					
FAILSAFE VALVES					

BOP CONTROLS: [illegible]
TESTER: [illegible]
ON LINE POD: [illegible] FUNCTION TEST: [illegible]
EMERGENCY ACOUSTIC: LAST DATE TESTED: ____________ FUNCTION ORDER: ____________
AMF: TEST DATE: ____________ ; RELEASE TIME: ________ SECS
TEST FLUID: ____________ ; FREEZE DEPRESSED TO: _____ °C ________ kg/m3
C/K. MANIFOLD FLUID: ____________ ; FREEZE DEPRESSED TO: _____ °C; DENSITY ________ kg/m3
SPHERICAL TEST PRESSURES: LOW: ________ kPa, ________ mins. HIGH: ________ kPa ________ mins.
RAM / VALVES TEST PRESSURES: LOW: ________ kPa, ________ mins HIGH: ________ kPa, ________ mins.
ACCUMULATOR MANIFOLD OPERATING PRESS: ANNULARS ________ kPa; RAMS / VALVES ________ kPa

ITEM	[illegible]		[illegible]		[illegible]	
	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
ANNULAR-UPPER						
ANNULAR-LOWER						
SHEAR						
PIPE						
PIPE						
PIPE						
[illegible] VALVE						
[illegible] VALVE						
[illegible]						
[illegible]						
[illegible]						
[illegible]						
[illegible]						

NOTE: [illegible] ; SHUT ACCUMULATOR PUMPS, AND THEN SIMULTANEOUSLY CLOSE ANNULARS AND PIPE RAMS
EXCEPT SHEAR AND ANY OTHER SIZED PIPE RAMS ON DRILL PIPE/TUBING.

AUXILIARY ITEMS

ITEMS	CHOKE MANIFOLD	STAND PIPE	UPPER KELLY COCK	LOWER KELLY COCK	[illegible] INSIDE BOP	[illegible] INSIDE BOP
TEST PRESSURE						
DATE						

ARE THE FOLLOWING ITEMS ON THE RIG AND IN GOOD OPERATING ORDER?

ITEM	YES	NO	ITEM	YES	NO
CIRCULATING HEAD AND PACKOFF			DETECTORS: GAS, ULTRAVIOLET, HEAT, SMOKE		
COCK TYPE BOP VALVE			FILL ADAPTER FOR NITROGEN BOTTLE		
STRIP-IN INSIDE BOP			DRILL PIPE FLOAT VALVE		
CROSSOVER SUBS TO ALL D.C.			HYDRIL DROP-IN DART		
KELLY COCK WRENCHES			PO BOY MUD-GAS SEPARATOR		
COCK TYPE BOP VALVE WRENCH			DEGASSER		
ADJUSTABLE CHOKE SPARE PARTS			PVT AND FLOW ALARMS		
ACCUMULATOR FLOWMETER AND BOTTLE TEST GAUGE			BREATHING APPARATUS, FIRST AID STATIONS		
C. THE MANIFOLD LINED UP FOR A KICK WITH ALL VALVES AND CHOKES OPEN THROUGH THE BUFFER TANK TO DEGASSER					

REMARKS: ____
____

CO REP: ____________ TOOL PUSHER: ____________ DRILLER: ____________

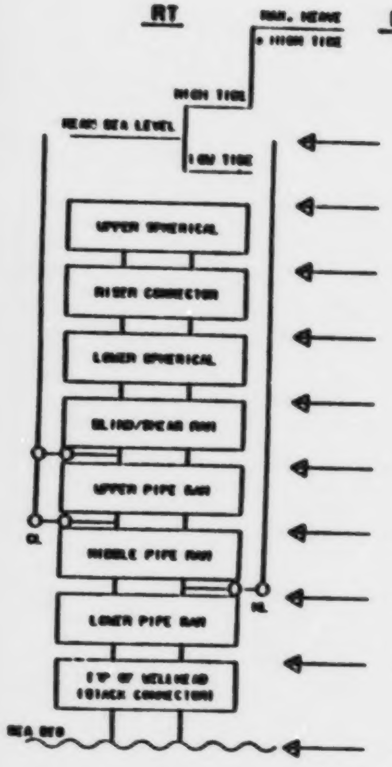
[illegible].CHT

Table 2.2

BOP DATA

RIG: ____________________

STACK: ____________________


RT
MAX. HEAVE
+ HIGH TIDE
HIGH TIDE
MEAN SEA LEVEL
LOW TIDE
UPPER SPHERICAL
RISER CONNECTOR
LOWER SPHERICAL
BLIND/SHEAR RAM
UPPER PIPE RAM
MIDDLE PIPE RAM
LOWER PIPE RAM
TOP OF WELLHEAD
(STACK CONNECTION)
CL
KL
SEA BED

RT-TOP OF ITEM (m)
(AT MAX HEAVE-HI TIDE)

DP STANDS

FAILSAFE VALVES

FUNCTION	VOLUME (litres)	TIME (secs)
CLOSE		
CLOSE - ASSIST		
OPEN		

BOP PREVENTOR FUNCTIONS

ACCUMULATOR OPERATING PRESSURES (kPa)	VOLUME (litres)			TIME (secs)	
	CLOSE	OPEN	BLOCK	CLOSE	OPEN
PRIMARY: SECONDARY:					
PRIMARY: SECONDARY:					

HEAVE-TIDE INDICATOR __________ m
WHEN MEASUREMENTS TAKEN

NOTE:

1. NORMAL ACCUMULATOR OPERATING PRESSURE ON ANNULARS WILL BE 4200 kPa
2. MAXIMUM ACCUMULATOR OPERATING PRESSURE ON ANNULARS IS 10,000 kPa TO PREVENT SEAL DAMAGE
3. OPERATE FAILSAFE VALVES AT 10,000 kPa
4. AMF CONNECTOR RELEASE TIME 2 1/2 MINUTES
5. RT-TOP OF ITEM-RECORD HEAVE-TIDE INDICATOR

2.2 Function Testing

The COGLA Regulations (Nov. 1980 - Section 131) stipulate the minimum frequency of function testing various major components in the blowout preventer system. Additional points to consider are:

a. Proper functioning of components is observed both visually and by checking required operating volumes/times/pressures.

b. Function tests at all operating control points are carried out at the same time the system is pressure tested (i.e. master panel, remote panels, etc.).

c. Elements of the diverter system should be function tested prior to drilling out any casing and thereafter weekly, including circulating through the system overboard to ensure clean lines. Pressure testing is not necessary.

d. Downhole tools should be visually checked and functioned on bit trips; auxiliary BOP tools (stabbing valve, kelly cock valves, etc.) should be functioned daily.

e. Test plugs etc. should be serviced and functioned if possible before use during a BOP system pressure test.

f. The entire subsea stack should be completely functioned once the LMRP is latched up to the main BOP package. (This should be done with the BOP on the spider beams and also if the LMRP has been disconnected from the main BOP once the stack has landed on the wellhead.)

g. Other blowout preventer system components:

   - Degassers - should be functioned and inspected each time the manifold is pressure tested.
   - Trip tank/pit level indicators - should be calibrated at the start of a well, and alarm settings should be checked daily.
   - Gas, smoke, u.v. and heat detectors - should be inspected and tested weekly.
   - Emergency shutdowns - should be tested at non-critical times (WOC, logging).

h. The acoustic control system should be functioned each time the stack is pressure tested.

i. The accumulator system should be checked/functioned each time the BOP system is pressure tested. The test must ensure that all the pipe rams and annular preventers on the stack can be closed using only the stored accumulator energy (air electric pumps shutoff) without the accumulator pressure dropping below 8400 kPa. Closing times/volumes should be recorded and compared to the normal stack test, and the time required for the air electric pumps to recharge the system should be recorded (see Table 2.3 for an example test chart).

j. A check for the appropriate pre-charge level on the stack mounted subsea accumulators should be performed on a routine basis.

k. Although not a strict BOP system function test, an overpull on the BOP/wellhead connector should be taken once the stack is landed to ensure the connector has latched. As well the LMRP/BOP connector should have an overpull taken to ensure proper latchup anytime the two packages have been split (due to temporary disconnection for weather reasons, etc.).

2.3 Pressure Testing

Minimum blowout preventer system pressure testing requirements are listed in the COGLA Regulations (Nov. 1980) under Sections 114, 115 and 116. Table 2.4 is a summary of these minimum requirements, including some of the additional blowout prevention equipment requiring testing.

NOTE: Tables 2.1 and 2.2 show examples of the type of information that should be recorded on each stack test, and information that should be available on the drill floor near the main operating panel. These are examples only and the forms may need to be altered for various well or equipment conditions.

In addition to the points mentioned previously, the following should be considered:

a. Personnel not involved in the actual pressure testing operation should keep clear of the test areas.

b. Casing pressure tests should be carried out to a pressure established by good engineering judgement and in accordance with regulations. However, a serious assessment of the consequences of pressure testing to values higher than 80% of the burst rating in air of the weakest component should be undertaken.

c. Test fluid volumes should be monitored closely to reduce the risk of casing rupture if the test plug or seal assembly leaks.

d. During any pressure test, the weakest component must be identified and considered when determining the maximum pressure to be applied. Axial forces resulting from applied pressure should also be calculated to guard against exceeding equipment tensile ratings.

e. Chokes should be pressure tested if they are of the positive seal type.

f. All components should be tested, if possible, to simulate applied pressure in a well control situation, i.e. fail safe valves should be pressured from the wellbore side, not from the choke/kill line side.

g. Primary and secondary seals on casing seal assemblies should be tested separately.

Table 2.3 ACCUMULATOR TEST

DATE: ____________

ACCUMULATOR:

ITEM	MAKE	MODEL	TYPE
ACCUMULATOR			
AIR PUMPS NO.			
ELECTRIC PUMPS NO.			

ACCUMULATOR DATA:

	VOLUME (litres)	PRECHARGE PRESSURE (kPa)	MANIFOLD OPERATING PRESSURE (kPa)
SURFACE			
SUBSEA			
RESERVOIR			

ACCUMULATOR FLUID:

PARTS (%): WATER ________ : GLYCOL ________ : SOLUBLE OIL ________.

DENSITY ____________ kg/m³ ; FREEZE DEPRESSED ____________ °C

OPERATIONAL DATA:

PUMPS	CUT IN PRESSURE (kPa)	CUT OUT PRESSURE (kPa)
AIR		
ELECTRIC		

CALCULATED ACCUMULATOR FLUID VOLUME:

FUNCTION	ITEM	VOLUME/ITEM	X NUMBER	= CALCULATED VOLUME
TO CLOSE	ANNULAR(S)			
	RAMS			
			SUBTOTAL	
TO OPEN	ANNULAR(S)			
	RAMS			
			SUBTOTAL	
OPEN & CLOSE			TOTAL	

FLUID VOLUME TEST:

PARAMETERS	SURFACE (SUR)	SUBSEA (SS)
P_0 : ORIGINAL ACCUM. PRESSURE (kPa)		
P_1 : FINAL ACCUM. PRESSURE (kPa)		
P_2 : PRECHARGE PRESSURE (kPa)		
V_0 : ACCUM. VOLUME (litres)		
ACTUAL VOLUME (litres)		

CALCULATED VOLUME = SURFACE VOL. + SUBSEA(SS) VOL.

$$= \left[\frac{V_0 P_2}{P_0}\left(\frac{P_0}{P_1}-1\right)\right]_{SUR} + \left[\frac{V_0 P_2}{P_0}\left(\frac{P_0}{P_1}-1\right)\right]_{SS} = \left[\frac{\_\_\_\,l \times \_\_\_\,kPa}{\_\_\_\,kPa}\left(\frac{\_\_\_\,kPa}{\_\_\_\,kPa}-1\right)\right]_{SUR} + \left[\frac{\_\_\_\,l \times \_\_\_\,kPa}{\_\_\_\,kPa}\left(\frac{\_\_\_\,kPa}{\_\_\_\,kPa}-1\right)\right]_{SS} = \_\_\_$$

ACTUAL VOLUME ≈ CALCULATED VOLUME

______ litres ≈ ______ litres

SUBSEA PRECHARGE = 6895 kPa + (10 kPa/m X WATER DEPTH) = 6895 kPa + (10 kPa X ________ m)
= ______ kPa

ACCUMULATOR PRECHARGE (P_2) PRESSURE TEST.

P_0 : ORIGINAL ACCUM. PRESSURE	____________ kPa
P_1 : FINAL ACCUM. PRESSURE	____________ kPa
V_0 : ACCUM. VOLUME	____________ litres
V_1 : FUNCTION FLUID VOLUME	____________ litres
ORIGINAL PRECHARGE	____________ kPa

CALCULATED P_2 = $\dfrac{\dfrac{P_1 P_0 V_1}{P_0 - P_1}}{V_0} = \dfrac{\dfrac{\_\_\,kPa \times \_\_\,kPa \times \_\_\,l}{\_\_\,kPa - \_\_\,kPa}}{\_\_\,l} = \_\_\,kPa$

ORIGINAL PRECHARGE ≈ CALCULATED PRECHARGE
______ kPa ≈ ______ kPa

REMARKS: ____

____

CO REP: ____________________ TOOL PUSHER: ____________________ DRILLER: ____________________

(175..0)1830231063.CHT

TABLE 2.4

ITEM	SITUATION A	SITUATION B	SITUATION C
CASING		as per COGLA regulation #116 or higher at the operator's discretion	as per COGLA regulation #116
SEAL ASSEMBLIES		same as casing pressure test.	same as casing pressure test.
WELLHEAD CONNECTOR	maximum w.p.	same as casing	same as casing
PIPE RAMS	maximum w.p.	same as casing	same as casing
BLIND SHEAR RAMS	maximum w.p.	same as casing	same as casing
LMRP CONNECTOR	same as annulars	same as annulars	same as annulars
ANNULAR PREVENTOR	1/2 of maximum w.p. closed on d.p.	1/2 of maxium w.p. closed on d.p.	1/2 of maximum w.p. closed on tubing
K/C LINES	maximum w.p.	same as casing	same as casing
FAIL SAFE VALVES STACK	maximum w.p.	same as casing	same as casing
MANIFOLD VALVES, CHOKES	maximum w.p.	same as casing	same as casing
STANDPIPE MANIFOLD	maximum w.p.	same as casing	same as casing
INSIDE BOP VALVE	maximum w.p.	same as casing	same as casing
DART SUB	maximum w.p.	same as casing	same as casing
CEMENT UNIT	maximum w.p.	same as casing	same as casing

SITUATION A: - on test stump
- after repairs to equipment

SITUATION B: - after latch up on wellhead
- after remedial downhole work
- every 14 operational days
- after casing is cemented

SITUATION C: - prior to DST's

3.0 PREVENTATIVE MAINTENANCE OF BLOWOUT PREVENTER EQUIPMENT

Reliable and prompt operation of blowout preventer equipment in an emergency is a necessity for a safe drilling operation. A blowout preventer system will, as all systems, only operate when required if it has been maintained properly. Proper maintenance of blowout preventer equipment is also an obvious necessity to protect the substantial investment in the equipment.

Maintenance of equipment is obviously much more critical when the equipment is subsea as compared to being on surface where it can be readily repaired or replaced. Therefore it is imperative that a discussion of preventative maintenance of blowout preventer equipment distinguish between the maintenance frequency of subsea and surface BOP systems.

3.1 Frequency

In general most components on a subsea stack should be overhauled every year while components on a surface stack should be overhauled every three years. There are exceptions to this rule of thumb. Check the manufacturer's suggested maintenance schedule and use rig sense to determine whether maintenance of certain equipment should be carried out earlier than the suggested schedule in the event of severe use or detrimental handling of equipment.

3.2 Procedure

a. All preventative maintenance of blowout preventer system equipment must be carried out only by qualified personnel.

b. All weld repairs must be carried out as per API specifications and duly recorded. The weld repairs should be inspected by an independent third party.

3.3 Replacement Parts

a. All materials and procedures used in the maintenance of BOP equipment must meet API 6A specifications.

b. Replacement rubbers for rams and annulars should be supplied by the original equipment manufacturer if possible. If they are not available from the manufacturer, they should be certified by the repair show as being of equal or better quality than the original parts.

c. All valve parts used should be certified by the repair shop as being of equal or better quality than the original parts.

4.0 WELL CONTROL PROCEDURES

4.1 Prerecorded Information

In the event of a well kick, certain information is necessary to enable the intruding fluid to be removed from the wellbore safely.

The type of information required is listed below and should be recorded and prominently displayed in the drillers doghouse. Figures 4.1 through 4.5 are examples of data sheets which may be used to record this information.

4.1.1 Pressures at Slow Circulating Rates

In order to know the circulating pressure drop due to friction at the slow pump rates used when killing a kick it is necessary to measure this pressure at the stand pipe at frequent intervals, for the slow pump rates selected.

Suggested frequency for recording these pressures are as follows:

a. Once every tour
b. Every 150 m
c. When mud properties change
d. When the BHA or bit nozzles are changed

4.1.2 Pressure Drop Up Kill and Choke Line

When the subsea BOP stack has been installed, the pressure drop up the kill and choke lines should be measured at the slow pump rates selected, and recorded. A method for obtaining those pressures would be with the pipe rams closed around d.p., pumping at slow rate with the flow returning up the choke line, record the pressure, then, maintaining the same pump rate, open the rams and record the pressure. By subtracting the second pressure from the first, the pressure drop due to friction up the choke line can be obtained. This pressure drop can vary with muds of different weights and properties, however, these changes can be extrapolated within tolerable degrees of accuracy.

In deep water operations, the effects of low temperature on fluid viscosity in long choke and kill lines can lead to pressure readings that would not be representative of a "kill" situation.

NOTE: It is usual in Canadian Frontier Offshore areas to fill the kill and choke lines with glycol or freeze depressed fluid. Consequently, it is necessary to take the difference in density of the mud in use and freeze depressed fluid into account when measuring shut-in casing pressures.

eg. Pressure Correction = (M.W. - 1020) x riser length x 0.00981

4.1.3 Maximum Allowable Casing Pressure

When killing a kick it is advisable to have calculated before hand a maximum casing pressure which, if exceeded, would result in formation breakdown and an uncontrolled downhole flow.

The weakest point in a well is considered to be the last casing shoe. It is required by the COGLA Regulations to conduct Formation Leak Off Tests (FLOT's) at certain points in the well to establish the formation strength. When the FLOT is known, the maximum allowable casing pressure (MACP) can be calculated. This figure should be recorded and prominently displayed at the choke controls and in the drillers doghouse.

MACP = (Leak off pressure) - (hydrostatic pressure at leak off depth due to mud weight in use)

A safety factor of 10% may be included in the calculation of MACP to allow for variations in fluid density.

4.1.4 Kick Tolerance

Kick tolerance can be defined as a measure of the maximum formation pressure than can be encountered in a well and circulated out without breaking down the weakest formation exposed. Kick tolerance levels are calculated regularly during the drilling of a well to minimize the risk of an uncontrolled downhole flow. (See Section 10.0 for further details on Kick Tolerance.)

4.1.5 BOP Dimensional Data

The height that the lower kelly cock must be above the rotary table to ensure that the tool joints are not across pipe or shear rams when shutting in the well, must be recorded.

This information together with a dimensional diagram of the BOP stack giving dimensions from the rig floor to the rams and hang off shoulders in the wellhead, should be prominently displayed in the drillers doghouse.

Figure 4.1

WELL CONTROL PRERECORDED INFORMATION

WELL NAME ______________________________ DATE ____________

PUMP INFORMATION	LINER SIZE IN	STROKE LENGTH IN	OUTPUT BBL/STROKE	FULL SPEED SPM	FLOW RATE BBL/MIN	PRESSURE PSI	REDUCED SPEED SPM	FLOW RATE BBL/MIN	REDUCED CIRCULATING PRESSURE P.S.I.	REDUCED SPEED
PUMP NO 1										NO. 1
										NO. 2
PUMP NO. 2										NO. 1
										NO. 2

HANG-OFF TOOL JOINT

________ Ft. Above RT.

Water Depth ________ Ft.

DRILL STRING CIRCULATING TIME	CAPACITY BBL/FT	LENGTH FT	VOLUME BBL	STROKES	CIRCULATING TIME - FULL SPEED MIN	NO. 1 CIRCULATING TIME - REDUCED SPEED MIN	NO 2 CIRCULATING TIME - REDUCED SPEED MIN
DRILL PIPE							
HEAVY WEIGHT DRILL PIPE							
DRILL COLLARS							
DRILL COLLARS							
TOTAL - SURFACE TO BIT							

CASING

Size ____________ in

Grade ____________

Weight ____________ lb/ft

Set At ____________ ft

ANNULUS CIRCULATING TIME		ANNULAR VOLUME BBL/FT	LENGTH FT	VOLUME BBL	STROKES	CIRCULATING TIME - FULL SPEED MIN	NO 1 CIRCULATING TIME - REDUCED SPEED MIN	NO. 2 CIRCULATING TIME - REDUCED SPEED MIN
OPEN HOLE ANNULUS	DRILL COLLARS							
	DRILL COLLARS							
	H.W.D.P.							
	DRILL PIPE							
CASING ANNULUS	DRILL PIPE							
CHOKE LINE								
CHOKE & KILL LINE								
RISER ANNULUS	DRILL PIPE							

TOTAL - BIT TO CASING SHOE						
TOTAL - CASING SHOE TO B.O.P. s						
TOTAL - BIT TO B.O.P. s						
TOTAL - BIT TO SURFACE						

DRILL PIPE

Size ____________ in

Weight ____________ lb/ft

Length ____________ ft

HEAVY WEIGHT DRILL PIPE

Size ____________ in

Weight ____________ lb/ft

Length ____________ ft

DRILL COLLARS

Size ____________ in

Weight ____________ lb/ft

Length ____________ ft

DRILL COLLARS

Size ____________ in

Weight ____________ lb/ft

Length ____________ ft

Bit Size ____________ in

Total Depth ____________ ft

B.O.P. Stack Rating ____________ PSI

Casing Burst Pressure ____________ PSI

Casing Test Pressure ____________ PSI

Choke Line Pressure Drop ____________ PSI (No. 1)

____________ PSI (No. 2)

Choke & Kill Line Pressure ____________ PSI (No. 1)

Mud Density ____________ lb/gal

Leak-Off Pressure ____________ PSI

Depth ____________ ft

Pressure Gradient ____________ PSI/ft

Hydrostatic Pressure (Leak-Off Depth) ____________ PSI

Maximum Allowable Choke Pressure ____________ PSI

Figure 4.2

WELL CONTROL CHART

DATE ____________________

WELL ____________________

REDUCED CIRCULATING PRESSURE ________ SPM = ________ PSI

SIDPP ____________________ PSI

________ SPM = ________ PSI

SICP ____________________ PSI

DEPTH ____________ ft.

PIT GAIN ____________________ BBL

MUD DENSITY INCREASE = $\frac{\text{SIDPP}}{\text{DEPTH ft. X .052}}$ .... ________ lb/gal

ORIGINAL MUD DENSITY .... ________ lb/gal

SAFTEY MARGIN .... ________ lb/gal

NEW MUD DENSITY .... ________ lb/gal

INITIAL CIRCULATING PRESSURE
Reduced Circulating Pressure + SIDPP
+ Overall Margin Backpressure
OR
Drill Pipe Pressure When circulating at
Reduced Rate with (SICP + Overall Margin - choke line pressure drop)

____________ PSI

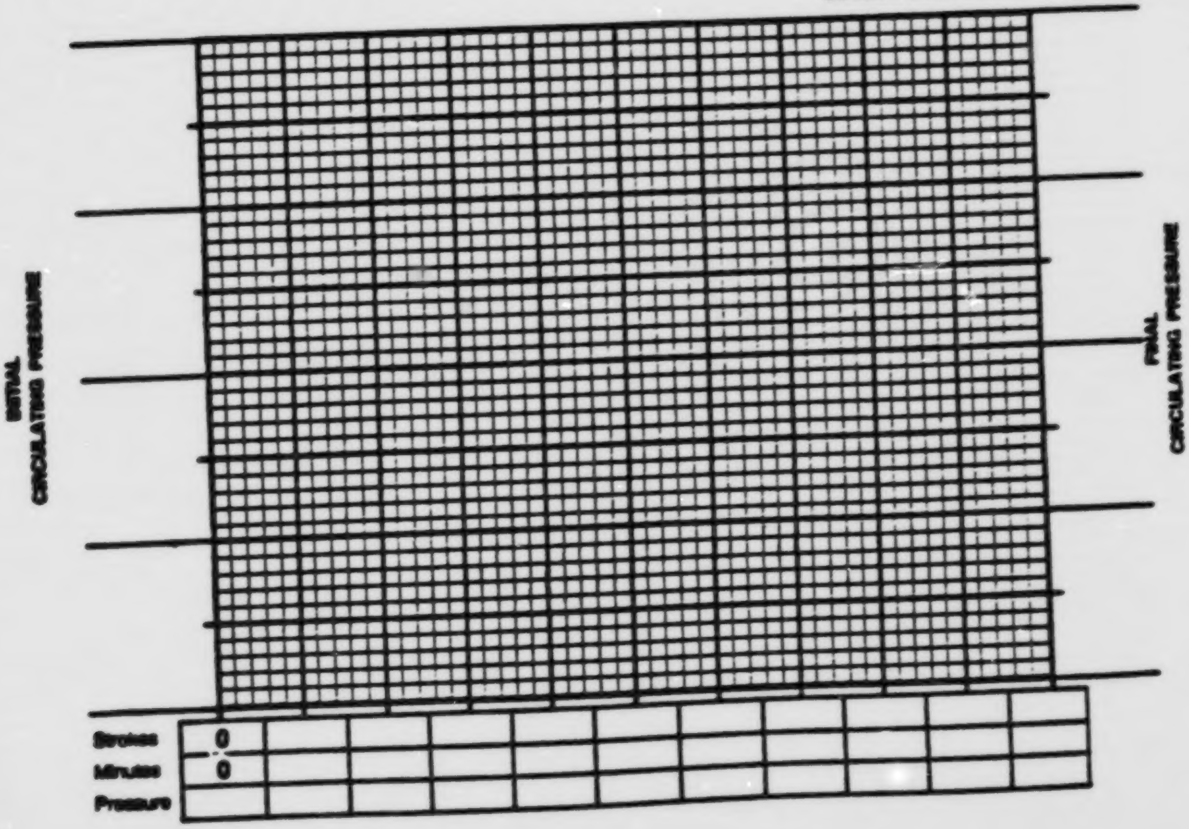
FINAL CIRCULATING PRESSURE
Reduced Circulating Pressure × $\frac{\text{New Mud Weight}}{\text{Old Mud Weight}}$

____________ PSI

+ Overall Margin Backpressure
OR
(Initial Circulating Pressure - SIDPP)
× $\frac{\text{New Mud Weight}}{\text{Old Mud Weight}}$

STROKES TO BIT FROM PRE-RECORDED INFORMATION ____________ stks.

Constant ____________ Strokes/Min



Strokes	0										
Minutes	0										
Pressure											

Constant Drill Pipe Pressure ____________________ PSI

Figure 4.3

WELL CONTROL PRERECORDED INFORMATION

WELL NAME ______________________________ DATE ____________

PUMP INFORMATION	LINER SIZE mm	STROKE LENGTH mm	OUTPUT m³/stroke	FULL SPEED SPM	FLOW RATE m³/min	PRESSURE kPa	REDUCED SPEED SPM	FLOW RATE m³/min	REDUCED CIRCULATING PRESSURE kPa	REDUCED SPEED
PUMP NO 1										NO. 1
										NO. 2

PUMP NO 2										NO. 1
										NO. 2

HANG-OFF TOOL JOINT

______ m Above RT.

Water Depth ______ m

						NO. 1	NO. 2
DRILL STRING CIRCULATING TIME	CAPACITY m³/m	LENGTH m	VOLUME m³	STROKES	CIRCULATING TIME - FULL SPEED MIN	CIRCULATING TIME - REDUCED SPEED MIN	CIRCULATING TIME - REDUCED SPEED MIN
DRILL PIPE							
HEAVY WEIGHT DRILL PIPE							
DRILL COLLARS							
DRILL COLLARS							
TOTAL - SURFACE TO BIT							

CASING

Size ______ mm

Grade ______

Weight ______ m³/m

Set At ______ m

							NO. 1	NO. 2
ANNULUS CIRCULATING TIME		ANNULAR VOLUME m³/m	LENGTH m	VOLUME m³	STROKES	CIRCULATING TIME - FULL SPEED MIN	CIRCULATING TIME - REDUCED SPEED MIN	CIRCULATING TIME - REDUCED SPEED MIN
OPEN HOLE ANNULUS	DRILL COLLARS							
	DRILL COLLARS							
	H.W.D.P.							
	DRILL PIPE							
CASING ANNULUS	DRILL PIPE							
CHOKE LINE								
CHOKE & KILL LINE								

RISER ANNULUS	DRILL PIPE				

TOTAL - BIT TO CASING SHOE						
TOTAL - CASING SHOE TO B.O.P. s						
TOTAL - BIT TO B.O.P. s						
TOTAL - BIT TO SURFACE						

DRILL PIPE

Size ______ mm

Weight ______ m³/m

Length ______ m

HEAVY WEIGHT DRILL PIPE

Size ______ mm

Weight ______ kg/m

Length ______ m

DRILL COLLARS

Size ______ mm

Weight ______ kg/m

Length ______ m

DRILL COLLARS

Size ______ mm

Weight ______ kg/m

Length ______ m

Bit Size ______ mm

Total Depth ______ m

B.O.P. Stack Rating ______ kPa

Casing Burst Pressure ______ kPa

Casing Test Pressure ______ kPa

Choke Line Pressure Drop ______ kPa (No. 1)

______ kPa (No. 2)

Choke & Kill Line Pressure ______ kPa (No. 1)

______ kPa (No. 2)

Mud Density ______ kg/m³

Leak-Off Pressure ______ kPa

Depth ______ m

Pressure Gradient ______ kPa/m

Hydrostatic Pressure (Leak-Off Depth) ______ kPa

Maximum Allowable Choke Pressure ______ kPa

Figure 4.4

WELL CONTROL CHART

WELL ____________________ DATE ____________________

REDUCED CIRCULATING PRESSURE ______ SPM = ______ kPa

______ SPM = ______ kPa

SIDPP ____________________ kPa

SICP ____________________ kPa

DEPTH __________ m

PIT GAIN ____________________ m³

MUD DENSITY INCREASE = $\frac{\text{SIDPP}}{\text{DEPTH m} \times .00981}$ .... ______ kg/m³

ORIGINAL MUD DENSITY .... ______ kg/m³

SAFTEY MARGIN .... ______ kg/m³

NEW MUD DENSITY .... ______ kg/m³

INITIAL CIRCULATING PRESSURE

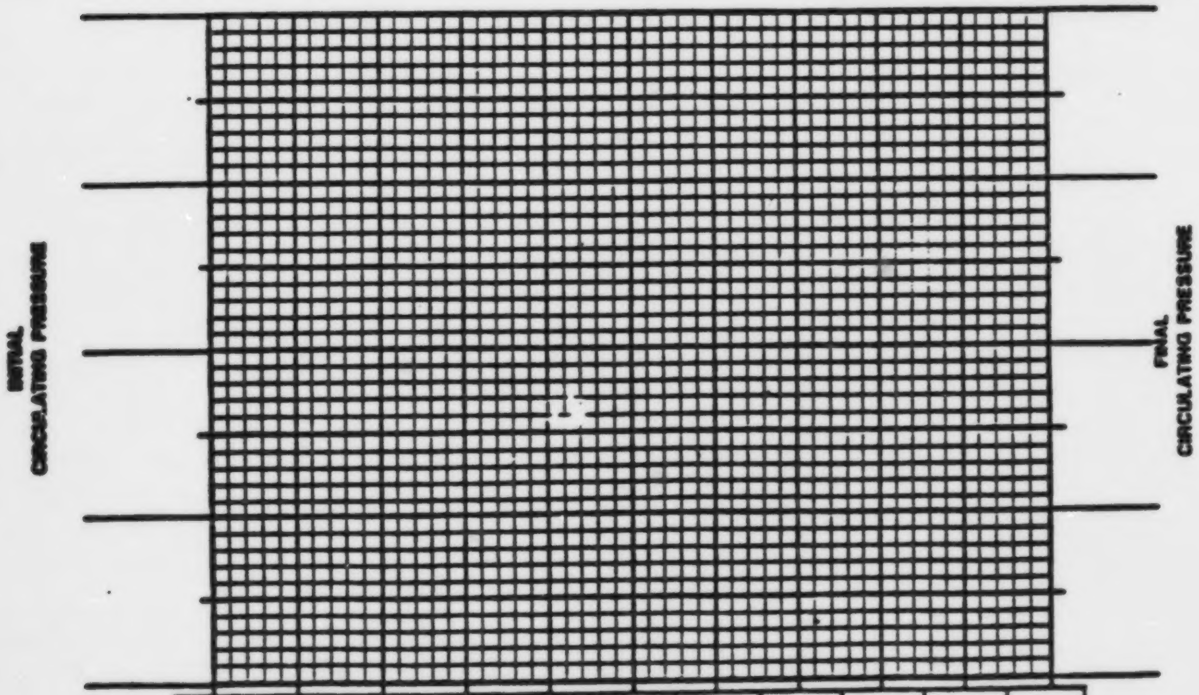
Reduced Circulating Pressure + SIDPP
+ Overall Margin Backpressure ____________ kPa

FINAL CIRCULATING PRESSURE

Reduced Circulating Pressure × $\frac{\text{New Mud Weight}}{\text{Old Mud Weight}}$
+ Overkill Margin Backpressure ____________ kPa

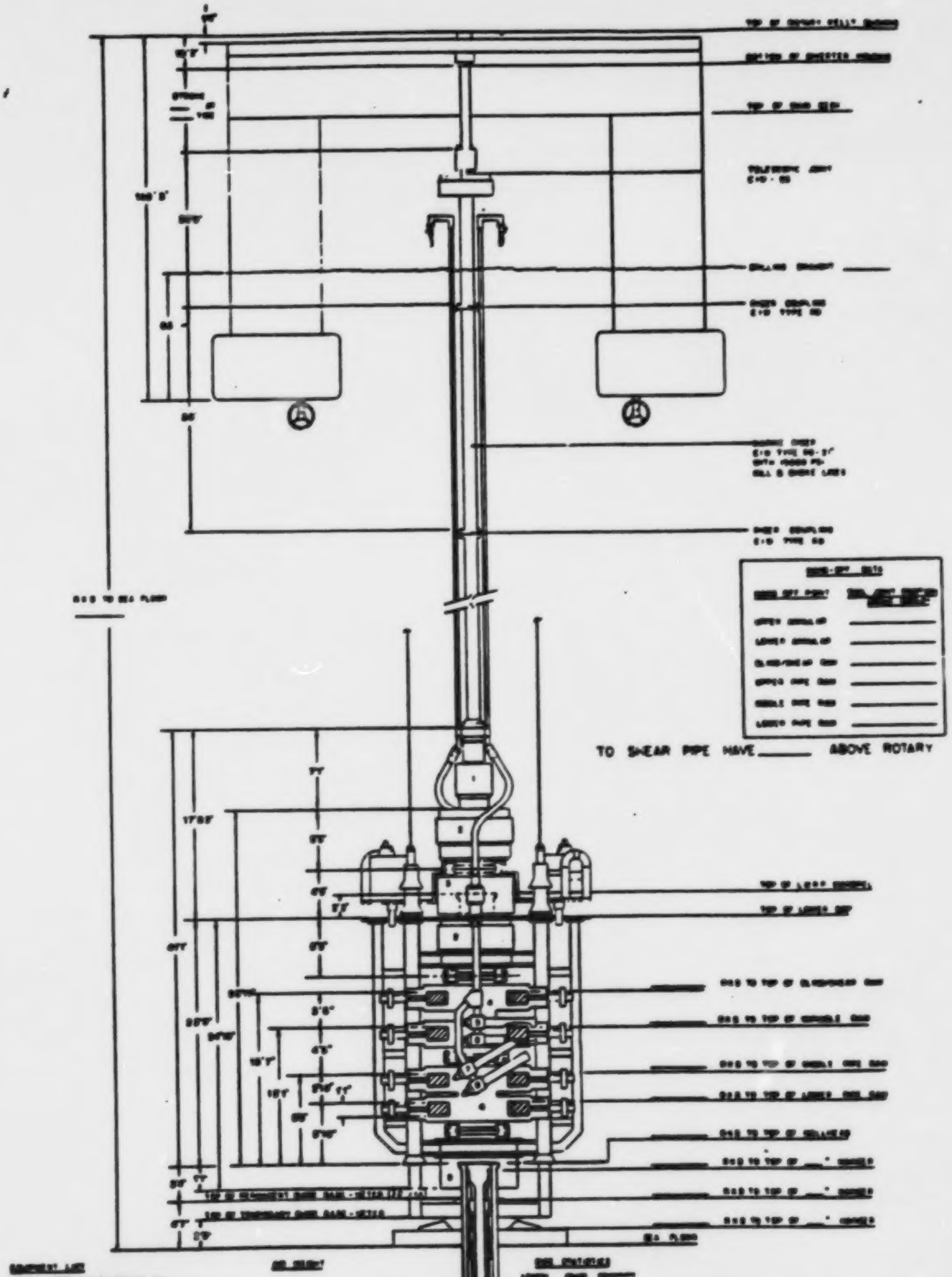
STROKES TO BIT FROM PRE-RECORDED INFORMATION ____________ stks.

Constant ____________ Strokes/Min



Strokes	0										
Minutes	0										
Pressure											

TYPICAL SEMISUBMERSIBLE SUBSEA EQUIPMENT ARRANGEMENT


TO SHEAR PIPE HAVE ______ ABOVE ROTARY

4.2 Well Control

The key to recognizing formation pressure increases while drilling is CHANGE. The Driller should be instructed to inform the mud logging unit and his Toolpusher of all changing parameters whiled drilling.

The Driller must make the decision to initiate well control procedures and he should ensure that the well is secure before notifying Toolpushers or Supervisors. Conference with senior personnel on the rig floor is not required. Diverting or shutting in a non-flowing well is at worst just a well control drill.

All flowing wells or those suspected of flowing should be controlled immediately. Early detection and action is critical for effective control. It is the responsibility of the Drilling Supervisor to ensure that each drilling crew is made aware of the proper well control procedures. It is the responsibility of the operators representative to supervise the well control operation.

Appropriate well control procedures vary with circumstances related to the current mode of operation. The following sections briefly discuss well control practices and procedures applicable to many different drilling operations.

4.2.1 Drilling Offshore with no Riser

When drilling while the riser is not connected, any flow that may occur can be neither diverted nor choked. Dependent on the severity of the problem, weighted mud or a barite pill can be pumped.

4.2.2 Well Control by Diverting

If a well flow occurs when drilling offshore with a riser and diverter attached, the downwind overboard line should be selected, and the diverter closed.

The valving should be arranged so that when the diverter is closed a valve also closes in the flowline and either one or the other overboard lines is open. Alternatively, it may be required to divert the flow along the flowline to the poor boy degasser. In this case, valves should be arranged to enable the flow to be diverted to the degasser and not to the shakers or overboard lines.

Well control while diverting would be limited to pumping heavy mud as quickly as possible.

4.2.3 Well Control Through a Choke

If a flow should occur when drilling with a BOP stack installed and the competence of the weakest formation has been established with a Pressure Integrity Test, the well should be shut-in and drill pipe and casing pressures recorded.

There are two methods in popular use for circulating out the invading fluid, the Wait and Weight Method and the Drillers Method. The Wait and Weight Method is preferred where there is adequate mixing facilities available. This method subjects the well to the least pressure. With both methods it is important that the MACP is not exceeded.

The Drillers Method is commonly used for circulating out influxes where shut-in pressures are near zero.

Both methods are detailed in material supplied by the Petroleum Industry Training Service (PITS).

Prior to drilling any hole section, it is important that the control policy to be followed in the event of a flow is defined, and all the crews are familiar with the well control procedures to be used.

4.2.4 Top or Annular Kill

This method can be utilized if the bit becomes plugged or if circulation cannot be established for any reason. The well can be killed via the annulus by allowing gas expansion followed by pumping mud into the annulus under pressure.

For further information on this technique, refer to PITS manual.

4.2.5 Well Control While Tripping

Prior to tripping, suitable tripping speeds should be calculated with respect to acceptable surge and swab pressures.

A flow check must always be made prior to tripping. Additional flow checks should be made after the first five stands out, and when appropriate in open hole, at the casing shoe, and before drill collars are pulled through the BOP.

The fail safes and upper choke valve should be closed while tripping.

If flow occurs, shut-in as quickly as possible to minimize the volume of influx. For detailed procedures refer to PITS manual.

4.2.6 Well Control with Partial Returns

Immediate Action: Lower pump rate or if necessary stop pumping through drill string. Do not allow influx up into the wellbore above the lost zone. Begin pumping into the annulus to keep annulus full. Keep the annulus shut-in.

Several techniques are available utilizing lost circulation materials to control partial losses with standard well control methods.

a. Continue pumping kill mud mixed with LCM material (mica, cane fibre) at a constant rate if the mud volume onboard can be maintained and if mud losses are not too great. Occasionally, close the choke partially to see if the annular and drill pipe pressures can be driven up. If so, shutdown and take new SIDPP, SICP. Then proceed to circulate.

b. If lost returns are increasing, the pumps can be shutdown and the well shut-in. Maintain constant SIDPP with the choke. Allow the well to stabilize for up to several hours. If the choke pressure increases indicating at least partial cure, pick a slower circulating rate and hence a new initial circulating pressure. Open the choke and then start the mud pump at the new slower rate and attempt to circulate heavy mud.

4.2.7 Barite Plugs

It may be necessary to spot a barite plug above the producing zone if it is important to maintain control of the well in the preceding circumstances. The purpose of the barite plug is two fold.

a. It can be mixed to up to 22 ppg to increase hydrostatic pressure above the flowing zone but beneath the lost circulation zone.

b. Ideally addition of dispersant to the slurry should enable a maximum settling rate of the barite, resulting in a hard plug.

4.2.8 Well Control While Logging and Running Casing

Prior to logging and running casing, the Well Management Team should meet and discuss the well control procedures to be employed if the well starts to flow while logging or running casing.

The well should be confirmed to be dead before starting logging operations or running casing.

While running casing, it is advisable to have a drill pipe/casing crossover on the floor to be installed in the event of a flow to enable the casing to be positioned below the rams to effect a kill. Alternatively, casing rams may be installed in the BOP stack prior to running the casing.

4.2.9 Well Control While Testing

The main objective is to conduct all procedures in a safe and complete manner so that the well is under control at all times. Some main areas of potential problems are as follows:

a. Perforating
b. Testing
c. Failure of tubing
d. Well flow when coming out of the hole with test tools
e. Failure of testing valve
f. Drive-off from location during testing

The Well Management Team should meet and discuss all potential problems and identify a procedure that will be used for each case prior to starting the test program.

Prerecorded information relating to hole volumes, tubing volumes, etc. should be kept in the drillers doghouse.

No smoking areas should be defined with no smoking allowed outside the quarters.

Emergency shutdown systems should be function tested prior to flowing the well.

All safety and life saving equipment should be checked, e.g. fire fighting, breathing apparatus, recharging system, first aid equipment, etc.

Arrange for review meetings, e.g. breathing apparatus, rescue methods, evacuation, operational concerns, etc., and ensure sufficient practice drills are run until proficiency is achieved.

Liner laps should be pressure tested before testing commences.

4.2.10 Well Control Drills

Certain drills should be conducted on a regular basis during the drilling of a well to ensure quick response and competency of the crews in the event of an emergency. The drills are as follows:

Diverter Drill

Prior to drilling out conductor casing and during the drilling of surface hole, Diverter Drills should be held with each crew.

The drill would consist of increasing the apparent pit level by hand and ensuring that the correct actions are taken by the driller and his crew.

For the purpose of the drill it is only necessary for the driller to go through the motions of closing the diverter and diverting the flow.

Hang Off Drill

This drill should be performed when the bit is inside casing. The apparent pit level is increased by raising float by hand during a trip out of the hole or prior to conducting a PIT.

The purpose of the drill is to ensure that the tool joint is in the correct position for hang off on middle pipe rams and utilizes the prerecorded information regarding BOP dimensions.

Pit Drill

The purpose of the Pit Drill is to train the Driller and Mudloggers to be constantly aware of the fluid level in the mud pits. Consequently, no advance notice will be given to the Driller that the drill is to be conducted.

After raising the mud pit float by hand, the reaction time and procedures followed by the Driller are noted. Half a minute is an acceptable reaction time but preferably should be quicker.

The Pit Drill should be held each week or more frequently if response is poor.

Trip Drill

This drill should be conducted when tripping at least once per week per crew.

The purpose is to ensure the Driller's vigilance in noticing a pit level increase during tripping and noting the reaction time to install and close a stabbing valve from the time the gain was noticed. It also serves to prove that the equipment is in good operating condition and that all the necessary crossovers are readily accessible when needed.

4.2.11 Tour Crew Change Procedures

a. Toolpushers should be on the rig floor before crew change and remain on the rig floor until the crew has actually assumed control and established the status of the operation.

b. The crew will change man for man. Individuals will not leave until their relief has arrived.

4.2.12 Crew Station

a. While drilling or circulating, there must always be a man at the shaker.

b. While tripping, a competent person should be assigned to fill out the trip record and monitor the mechanical trip tank indicator. The Mudlogger and the Driller should check frequently to ensure the Trip Record is being correctly documented.

c. While drilling or circulating there must always be a man in the mud room - mud pit area. This man should not be used for floor relief.

5.0 KICK TOLERANCE

5.1 Definition

Kick tolerance can be defined as a measure of the maximum formation pressure that can be encountered in a well and circulated out without breaking down the weakest formation exposed.

5.1.1 Rationale

The rationale for using kick tolerance calculations during the drilling of a well is to minimize the risk of an uncontrolled downhole flow.

5.1.2 Limitations

There are several forms of kick tolerance formula in existence, some more conservative than others. While it is important that the risk of an uncontrolled flow is minimized, the kick tolerance formula used should not be restrictive to the point of necessitating premature setting of a casing resulting in the inability to drill the well to planned total depth.

In selecting a suitable kick tolerance formula, the assumption must be made that a kick, once detected, will be efficiently handled and removed from the wellbore in a competent manner.

It is important that kick tolerance is used and should take into account surge gradient, PIT values, size of influx, etc. If the actual influx is greater than the assumed influx a reduced kick tolerance results.

A typical kick tolerance equation is:

$$K_t = \frac{PIT \cdot D_{tvlo} - MW\,(Li + D_{tvlo})}{D_d} - \text{Surge gradient or choke line backpressure whichever is greater}$$

Where: K_t = Kick tolerance
PIT = Lowest value of pressure integrity test evaluated in the open hole section
D_{tvlo} = True vertical depth of leak off point
MW = Mud density in use
Li = Influx length (true vertical)
D_d = Current true vertical drilled depth

As K_t tends toward zero it becomes critical to minimize the size of the influx. This can be achieved by early warning of an influx by:

- Flow checking every drilling break
- Dummy connections
- Flow check on variations of torque and pump pressure
- Particular care taken on tripping out with flow checks every 10 stands.

Also the size of the influx can be minimized by controlling penetration rate. This serves two purposes:

a. The amount of pressured formation opened up prior to indications on surface, is minimized, and

b. The ECD is reduced for a given mud weight, since there are less cuttings in the hole, therefore, reducing the hydrostatic due to mud at the weakest formation.

5.1.3 Floating Drilling Units

Consideration should be given to the effect of the loss of hydrostatic head from mud in the marine riser in the event the drilling vessel has to disconnect and move off location.

In relatively shallow water such effects can be readily compensated for, however in deep water operations it is imperative that all personnel are aware of such consequences.

5.2 Kick Tolerance in Oil Base Drilling Fluid

Since gas is soluble in oil, the question arises "should the kick tolerance equation be modified" when using oil based muds.

In oil based muds any gas influxes remain dissolved in the mud until reduction in temperature and pressure conditions result in the gas coming out of solution to produce a bubble quite near the surface. However, in water based muds the gas does not go into solution and consequently not only is the influx noticed quickly but the gas bubble also migrates up the annulus faster than the annular flow rate of the mud.

From Figure 5.1, it can be seen that if the rig crew could reliably detect a 10 bbl pit gain, a gas bubble would reach surface in about 30 minutes with a water based mud and in approximately 85 minutes with an oil based mud.

Hydrocarbon gas solubility in oil based mud significantly alters the surface responses to a kick while drilling. Gas entering the wellbore dissolves in oil based muds and limits the volume increase seen at the surface to that of condensed gas.

A method of kick detection commonly used on the rig is to stop the pumps and check for flow. This method is quite successful when the kick is well advanced and annular flow rates become large as rapid expansion of the entrained gas occurs. However, at greater depths where the gas is dissolved in the oil mud, short flow checks (2 - 3 minutes) are insufficient to detect a flow. When using oil muds, flow checks should be 15 minutes minimum.

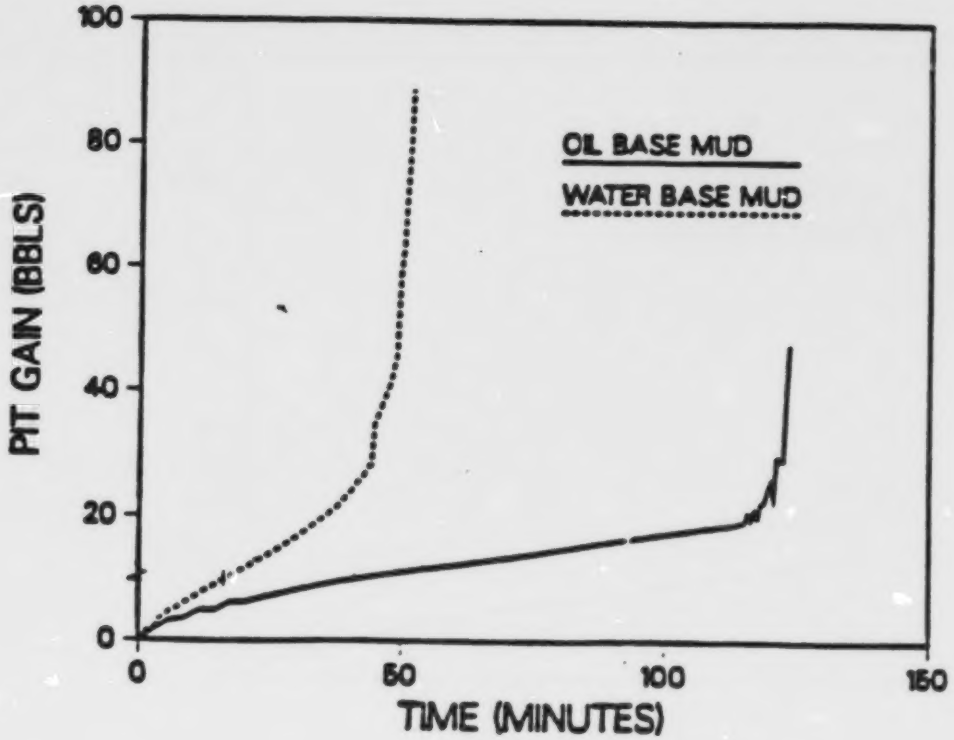


FIGURE 5.1

GAS MIGRATION IN MUD

After being detected, a small kick should be easier to control in oil based muds than in water based muds. Gas solubility will limit pressure rise and reduce the danger of breaking down the weakest formations.

Although the indication of a gas kick in an oil mud is somewhat delayed compared with a gas kick in a water based mud, the adoption of modified techniques allows kicks to be safely circulated out. It is not considered necessary to modify the kick tolerance equation to make it more conservative when using oil mud.

5.3 Formation Leak Off Test Procedures

Formation Leak Off Tests (FLOT's) are conducted to determine the strength of the weakest formation exposed in the wellbore. Figure 5.2 shows some typical examples of these tests.

A FLOT should be conducted:

a. After drilling out a casing shoe and making 5 m of new hole.

b. Consideration should be given to reconfirming original value of the FLOT when an over pressured zone is about to be penetrated.

Prior to conducting a test it is necessary to estimate the maximum surface pressure required with the mud weight currently in use to cause the formation to yield. This can be done with the help of a fracture gradient plot for the area under consideration.

It is also a help if a minimum volume line is established prior to the test. In the case of a test to be conducted after drilling a casing shoe and 5 m of new hole, the minimum volume line can be constructed during the casing pressure test prior to drill out by plotting pressure versus volume pumped. Graphs can also be used to establish a minimum volume line, and it is necessary to do this to determine the optimum rate of displacement during the test. For example, the displacement rate during the test should be such that the gradient of the pressure versus volume line should approach the grad

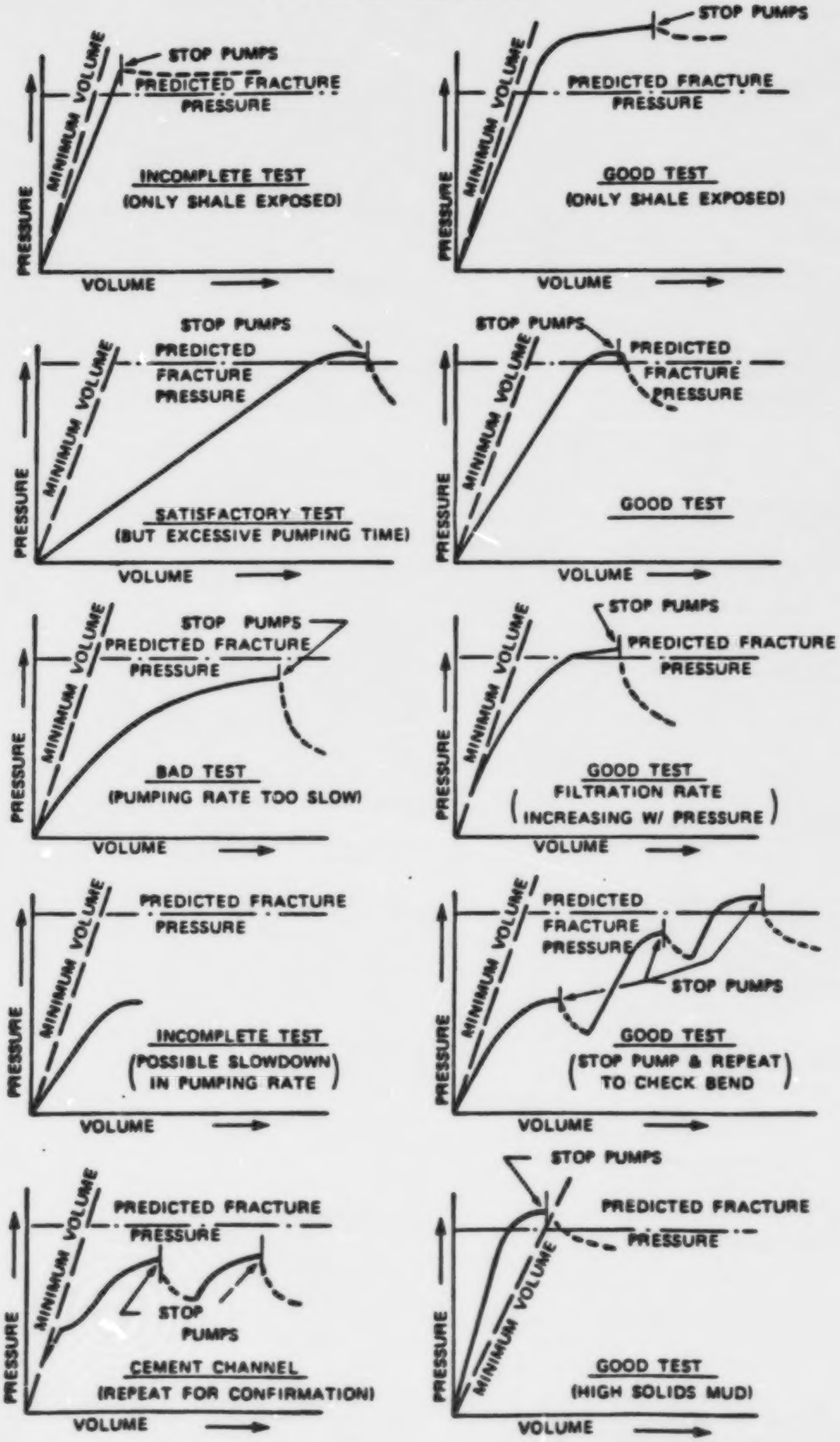
h. Beware of high friction losses. Normally friction losses are very low and need not be considered; check for line restriction. In deep wells using small bits and drill pipe, friction effects can be reduced by pumping down the annulus or annulus and drill pipe together.

i. Water depth corrections should be applied to the estimated fracture values.

j. The drill pipe should be inside the previous casing when conducting a FLOT.

FIGURE 5.2

PRESSURE TESTS
TYPICAL EXAMPLES



SECTION 7

WELL ABANDONMENT

1.0 GENERAL

COGLA's drilling regulations specify abandonment requirements for wells on Canada lands. The relevant regulations are #122(3), #203-213 and #215-219. The comments below are intended to provide guidance on abandonment procedures.

Wells drilled on the Scotian Shelf may be suspended for various reasons, including "waiting on weather", "waiting on ice", seasonal shutdown, rig servicing and others. The following notes include guidelines for well suspension.

2.0 ABANDONMENT

2.1 Open Hole

Consideration should be given to increasing the design volume of abandonment plugs, to deal with potential hole irregularities, rheological constraints, and other factors.

Plugs should be placed with a non-upset type pipe stinger on the bottom of the main drill pipe string, to minimize plug movement/contamination when tripping out.

Unsupported open hole plugs should be tagged following placement.

Mud/cement spacers should be utilized on both sides of the cement plug, especially if an oil mud is in use; the spacer must be compatible with both types of fluids and should water wet the formation if possible.

2.2 After Well Testing (following a DST, or a number of DST's)

For open hole tests, abandonment of the zone should follow the COGLA Regulations and the guidelines above for open hole abandonment.

For cased hole tests (where perforations are open) the zone must be abandoned by one of the methods detailed in the COGLA Regulations Section 211(2), subject to the following:

a. A 30 m cement plug should be placed on top of a bridge plug (within 30 m of the top perforation or as evaluation program allows).

b. A minimum 50 m cement plug should be placed (with the bottom of the plug within 30 m of the top perforation) if no bridge plug is first run.

c. Both the above plugs should be pressure tested prior to proceeding with any subsequent operations.

d. If cement is squeezed into the perforations, sufficient cement must also be left inside the casing such that the cement top is 25 m above the top perforation, and the plug must be pressure tested to a pressure above the leak off pressure of the formation being squeeze cemented.

2.3 Cutting and Retrieving Casing and/or Wellhead Assemblies

Can be accomplished using explosives, or mechanical/chemical cutting equipment.

COGLA Regulation #210(l)(f) specifies that all annuli open to formations must be sealed; in addition where equipment configuration permits these annuli can be pressure tested.

Mechanical bridge plugs should be placed in every casing string in multiple string wells.

3.0 SUSPENSION

Using the definition in the COGLA Regulations: "suspended - means, in respect of a well or test hole, a well or test hole in which drilling or producing operations have temporarily ceased".

Consideration should be given to the period for which the well will be suspended. If the well is to be left, with BOP stack in place, for a short period (as in the case of weather alert) then all that is required is to hangoff the drill string in the BOP's, and shut in the well.

If it is necessary to retrieve the BOP stack for repairs, then a retrievable packer/plug/circulating valve assembly should be run and set below the wellhead, and pressure-tested appropriately.

In the case of a long-term suspension (in the case of a seasonal shutdown, for example), the well should be suspended as if it were being abandoned, unless it has been left with casing set, not drilled out, and not perforated (which would normally be the case). In the latter case it may be considered acceptable to dispense with cement plugs and rely upon a bridge plug or plugs.

SECTION 8

INVESTIGATION OF GEOPHYSICAL PRESSURE PREDICTION METHODS ON THE SCOTIAN SHELF

1.0 ACKNOWLEDGEMENT

The Task Force wishes to extend its thanks to Ms. Mimi Fortier of COGLA who authored this report. Further, the Task Force wishes to acknowledge the assistance obtained from a COGLA study entitled "Overpressuring Study of the Scotian Shelf" by B. Young, Engineering Branch, Canada Oil and Gas Lands Administration, March, 1986.

The Task Force Editorial Committee has prefaced Ms. Fortier's report with an Introduction and Conclusions.

2.0 INVESTIGATION OF GEOPHYSICAL PRESSURE PREDICTION METHODS ON THE SCOTIAN SHELF - COGLA REPORT

2.1 Introduction

As a contribution to the work of the (CPA's Frontier Drilling Committee) Geopressure Drilling Task Force, COGLA reviewed "Authority to Drill a Well" (ADW) submissions to compare predicted to actual overpressure tops. Overpressure predictions from the ADW's of all Scotian Shelf geopressured wells drilled since 1981 were compared with actual conditions found when the wells were drilled. This report reviews the result's of the study, reports the success rate of predictions, and discusses predictive methods.

2.2 Conclusions

2.2.1 Better success was experienced in predicting overpressure tops in more densely drilled areas.

2.2.2 Correlation of seismic markers associated with overpressure prone stratigraphic units, combined with geophysical seismic velocities, provided the most reliable predictive method. Seismic velocity was rarely used as a stand-alone method.

2.2.3 Of 27 wells with both predicted and actual geopressured tops, 74% predicted the tops within 10% of the actual depth, and 60% of them within 5%.

2.2.4 Previous drilling experience in the area increases prediction accuracy. Based on this, less experienced operators, or new operators to the area would benefit from shared well information concerning formation pressures and seismic velocities.

2.3 INVESTIGATION OF GEOPHYSICAL PRESSURE PREDICTION METHODS ON THE SCOTIAN SHELF

Report by Mimi Fortier - November, 1985 - COGLA

The study of offshore pressure prediction methods was initiated with the survey of wells on the Scotian Shelf - an area where abnormal pressures have caused serious drilling programs. Similar surveys of the Grand Banks and Beaufort Sea wells will be carried out at a later date.

"Authority to Drill a Well" (A.D.W.) submissions have been reviewed for all wells drilled in overpressure section on the Scotian Shelf since 1981. Although a prognosed drill depth to overpressure is usually given, rarely is the method of prediction described. The prognosed depths to overpressure have been compared to the observed pressure data obtained post-drilling. Following are observations on the accuracy of pressure prediction and brief notes on methods of prediction where these were explained.

2.3.1 Accuracy of Pressure Prediction

A total of 35 A.D.W.'s were reviewed for this survey. With the exception of very few well prognoses, operators have attempted to approximate the depth to top of the pressure transition zone for drilling safety reasons. In the case of four recent wildcats, overpressure was not expected, no attempt to predict a top was made and no abnormal pressures were encountered while drilling. The remaining 31 are located in areas where abnormal pressure regimes are generally expected at depth. In many cases both the top to the transition zone or "soft" overpressure and the top to "hard" overpressure are estimated.

These prognosed depth values have been compared to post-drill depths to overpressure which have been calculated in-house at COGLA by staff of the Engineering Branch. Hence two numbers describing the fluid pressure conditions are compared that may be defined differently by an operator and COGLA. In this survey, however, the definitions were assumed to be the same. Success of prediction was measured by calculating the percentage of the total depth to top overpressure by which the predicted top differed. This figure was unavailable in four cases, two did not predict a top and another two wells did not encounter overpressured section above the total depth of the well.

Success of geopressure prediction ranged from 20% (in two cases) to as low as 0.1%. 74% of the 27 wells predicted top of overpressure within 10% of the actual depth, 60% within 5%.Those wells whose prognoses were over 10% off are situated for the most part in unexplored areas of the basin and all are wildcats. That is not to say that some prognoses of wells in new areas of exploration were not more accurate. Many wildcats encountered overpressured section within 1 or 2% of the prognosed depth.

These prognoses are well within the realm of time-to-depth conversion accuracy from seismic data. The seismic velocity accuracy was measured by comparing the prognosed top of Mississauga Formation to the drilled top. Mississauga was chosen because it is the deepest geological marker interpreted consistently across the basin. The average prediction error in prognosing drill depth to Mississauga falls around 2% with two-thirds of prognosis error falling below that number. Larger errors in Mississauga prediction may be due entirely to seismic mis-correlations rather than larger errors in velocities.

Success of geopressure prediction appears to rely heavily on the concentration of well information in a given area. Prediction drill depths to overpressure can average less than 2% of the actual post-drill depths in cases where structures in the area have already been delineated. Whereas in unexplored regions or even in the case of a first delineation well on a structure, the success rates calculated show that prediction of overpressure occurrence can be extremely tenuous. For instance, in the case of two wells drilled on neighbouring structures, the prediction error in the second well was five (5) times larger than the first despite the fact that they were operated by the same company. Operators with little experience in the basin produced estimates that range in prediction accuracy from 10% to 20%, less accurate than their time to depth conversion. The high number of cases where accuracy fell within less than 5% can be explained by the historical predominance of two operators in the basin.

So the numbers alone would suggest a reliance on familiarity with the overpressure related stratigraphy to predict its depth of occurrence and not in a consistent velocity prediction method.

It is interesting to note at this point that statements on the success of prediction have been quantified in terms of percentages. If we look at the absolute difference values between the predicted and drilled depths, these range from as low as 10 m to as high as 1100 m. For instance an accuracy of 4% at a 4500 m depth represents an absolute difference of 180 m. In terms of depth prediction from seismic data, 4% is very accurate. However most drilling engineers will probably want overpressure pinpointed well within 180 m.

2.3.2 Geophysical Methods of Pressure Prediction

The A.D.W. submissions almost never contain a discussion or even mention of methods of overpressure prediction used in the prognosis despite the fact that almost all include some predicted drill depth to overpressure. Very few have included an interval velocity or interval transit time curve and even fewer mention that seismic velocities were used to predict overpressure. Some mention prediction of top overpressure via stratigraphic correlation from adjacent wells based on seismic interpretation. As a result of the lack of information on geophysical prediction methods, general comments from Scotian Shelf operators on methods of pressure prediction were solicited by telephone.

It appears that all operators have made an attempt in the past, if not currently, to use seismic velocities to predict the occurrence of overpressured section. Some still study velocity analyses every time they drill a well to look for reversals in the interval velocity curve with depth. Only one geophysicist canvassed would imply that he uses seismic velocities alone to predict overpressure by comparing the interval transit time curve with a normal shale compaction curve and measuring deviations of the two curves. Another operator has mapped variances of the Acheson velocity equation with limited success in one case and admitted failure in another. This method is very dependent on the amount of well control and the velocity information that can be obtained for each well. In yet another example, overpressure was predicted at a depth where a noteable decrease in seismic interval velocity was documented and yet no abnormal pressures were encountered throughout the drilling of the well.

Apart from the unreliability of seismic velocities, the existence of overpressure, the depth and the section in which it occurs are also highly variable over the basin. Stratigraphic correlations with the help of seismic horizontal control are also used with limited success. The majority of operators use both the study of seismic velocities and stratigraphic correlations to predict overpressured section. Rarely are seismic velocities used as a stand alone method.

Major operators claim the best success is obtained by using seismic data to make stratigraphic correlations. Most operators claim they cannot derive a valuable and reliable prediction from velocity analysis of seismic data because interval velocities derived form seismic data at depths overpressuring occurs are not consistent. The overpressured sections are too deep, normal move-out time differentials are too small over cable lengths used, transmission losses too great, and not enough detail can be obtained to break down intervals in the sections reliably to calculate accurate interval velocities form an already error-prone r.m.s. velocity curve.

It is noted, therefore, in the Venture-Sable Island area where overpressured section is deep and generally includes fast velocity lithologies, that the method of studying seismic velocities is futile. Fortunately, well control is dense enough and the geological section provides characteristic reflectors which are easy to trace horizontally on the increasingly greater seismic control, such that the seismic stratigraphic correlation method works well to predict depth of overpressure. On the other hand, in areas like the southern Sable Subbasin, for example, well control is more sparse, the clastic section in which abnormal pressure exists is constantly changing laterally, especially across faults. As a result, the prediction method based on seismic correlation breaks down due to the unreliable identification of seismic markers. However, the abnormally pressured section is generally shallower and contained within a section of lower velocity shelf-edge clastics, and therefore it is easier and more reliable to look at changes in interval seismic velocities. Hence, it is not only a skill to predict overpressure, but also to choose a reliable method or combination of methods to use in making such predictions based on a knowledge of the geology of the area.

2.3.3 Conclusions

Conclusions of the survey are not dissimilar to those stated in Manadrill's report and therefore recommendations are also similar. More shared well information concerning formation pressures and velocities among Scotian Shelf operators increases the quality of pressure prediction. At this point, further studies of the nature of the overpressure and the associated geology should bear more fruitful results than detailed investigation of geophysical procedures in pressure prediction.

Studies of pressure prediction on the Grand Banks and certainly on the Beaufort Sea wells should result in more straight forward methods due to the nature of overpressure and the geologic column in which it occurs.

SECTION 9

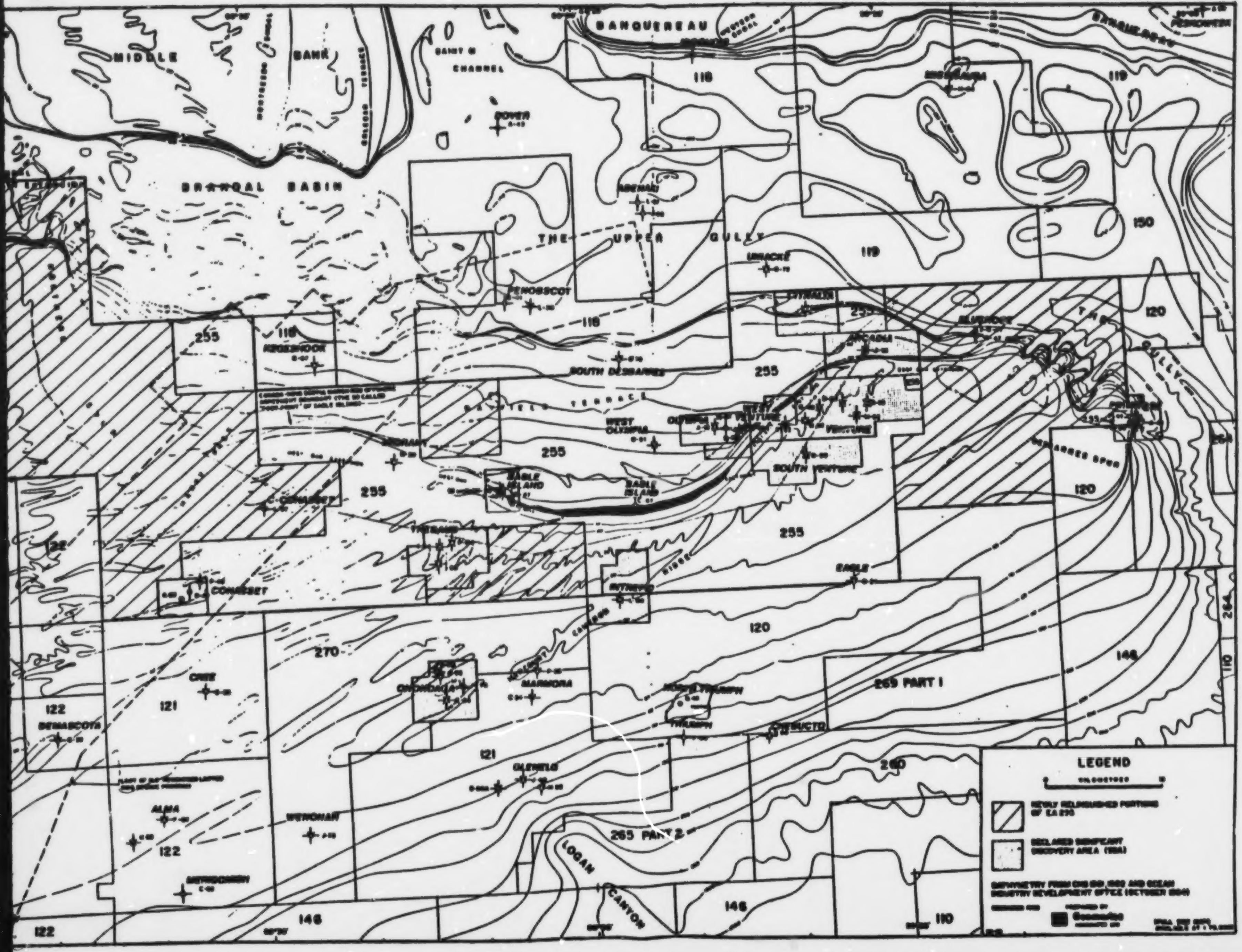
GEOPRESSURE DETECTION

This report was authored by EPI Resources Ltd., Halifax, under Project #59-2 and a budget authorized by the CPA. The conclusions were subsequently edited by the Geopressure Drilling Task Force.

ACKNOWLEDGEMENTS

EPI appreciates the co-operation obtained from the following companies:

1. Mobil, Shell, Petro Canada, Home Oil, Husky/Bow Valley
2. Schlumberger
3. COGLA Halifax
4. Analysts
5. Exlog
6. Baroid
7. Magcobar
8. Nova Scotia Department of Mines and Energy


MIDDLE BANK
BANQUEREAU
SAINT M CHANNEL
DOVER
SHUBENACADIE BASIN
THE UPPER GULLY
THE GULLY
PENOBSCOT
SOUTH DESBARRES
WEST OLYMPIA
OLYMPIA
VENTURE
SOUTH VENTURE
ARCADIA
SABLE ISLAND
MIGRANT
THEBAUD
EAGLE
INTREPID
NORTH TRIUMPH
TRIUMPH
CHEBUCTO
ONONDAGA
MARMORA
CREE
DEMASCOTA
ALMA
WENONAH
GLENELG
LOGAN CANYON
DESBARRES SPUR
118
119
150
120
255
264
110
146
269 PART I
265 PART 2
260
270
121
122
LEGEND
KILOMETRES
NEWLY RELINQUISHED PORTIONS OF EA 230
DECLARED SIGNIFICANT DISCOVERY AREA (SDA)

1.0 INTRODUCTION

Following the Uniacke G-72 surface blowout (February/March 1984) and the West Venture N-91 underground blowout (September 1984 - August 1985), specific Operators, Industry and Government commenced a re-evaluation of all offshore drilling practices/procedures, communications and organization, and the training of personnel.

In March 1985, a COGLA sponsored report entitled "An Examination of Safety Procedures and Practices used in Exploratory Drilling Operations Conducted in Abnormally Pressured Formations in the Scotian Shelf Area" was completed. One point of concern expressed in this report was that more Industry effort was required in the areas of detection and interpretation of abnormal pressure data. During 1985, COGLA, Ottawa Engineering Branch, undertook an "in-house" Study of Scotian Shelf Overpressuring (preliminary draft March 1986).

The OOD Drilling Committee requested EPI Resources Ltd. to prepare a proposal to examine specific detection methods and to review historic drilling data which would indicate the detection parameters that reliably indicate the onset of the geopressure transition zones. An EPI proposal was submitted to the Drilling Committee in October 1985.EPI was subsequently awarded the study on December 18, 1985, with an approved budget level of $25,000 specified for the Phase I scope of work.

Of some 40 geopressured wells initially proposed for analysis, only 19 wells have been reviewed in the Phase I of the study due to schedule and budget limitations. At this stage of review it is felt that several meaningful observations/ conclusions have been made.

This present study does not attempt to address the theories and mechanisms by which the geopressures may have been formed. It attempts to concentrate on the detection and interpretation aspects currently in use by Operators and service companies on the Scotian Shelf.

Section 2.0 provides the Conclusions and Recommendations and Section 3.0 provides a Summary of the work completed during Phase I of the study.

Sections 4.0, 5.0 and 6.0 provide the initial Scope of Work, Study Methodology and Appendix respectively.

The continuation of further Phases of the study is to be decided by the CPA-OOD Drilling Committee during the spring of 1986.

2.0 CONCLUSIONS/RECOMMENDATIONS

2.1 Conclusions

2.1.1 Of the five parameters examined for relative effectiveness as a detector of impending overpressure, connection/trip gas (61% fair to good) was the most reliable. In order of decreasing effectiveness, D-Exponent, electric logs, shale density and penetration rate, followed. A tabulated comparison of the detection parameters and the ratings method used are included in the following Summary section.

2.1.2 The data reliabilities quoted in this report do not necessarily reflect the potential capability of specific parameters to detect geopressures, as the timing of the data gathering dramatically effects the perceived effectiveness. Reliability of the latter four indicators (see 2.1.1 above) could have been enhanced by more regular data collection (particularly electric logging) by consideration of variable lithology or simply by applying the technique in other portions of the hole.

2.1.3 No single parameter is 100% reliable. Detection of overpressure will be most assured through rigorous collection, integration and monitoring of all available parameters. The five parameters studied, if taken together, indicated pending onset of overpressure in 78% (fair to good) of cases studied.

2.1.4 If early detection of overpressure is of critical concern in a drilling program, serious consideration should be given to adding additional data sources. Measurement while drilling sensors can provide real time resistivity, gamma-ray, bottom hole temperature, as well as downhole bit weight/torque, which should aid greatly in early detection.

2.2 Recommendations

2.2.1 Offshore Operators should initiate a standard approach to collecting and formatting data "on-board" the rig. First line supervisors should be confident that the detection data being presented, reviewed and interpreted is consistent. Direct comparisons with offsets wells on the same format basis would be useful on compressed scales for predicting most likely trends on wells being drilled.

2.2.2 While this short study only reviewed approximately one half of the geopressured wells encountered to data on the Scotian Shelf, there is data available to expand the data base into a more consistent format to enhance improvements in detection and predictive methods. It is recognized that each individual Scotian Shelf Operator utilizes their own in-house engineering to further understand the drilling regime, however new, and perhaps less experienced Operators also need to have access to a common data base in order to reduce the occurrence of well control problems. Industry and Government need to decide who is to be responsible for establishing, maintaining and controlling the geopressure information data base.

2.2.3 Further engineering studies should be undertaken in the following areas:

a. D-exponent - to develop normal trend and geopressure overlays specifically for the Scotian Shelf. Due to the varying lithology encountered in Scotian Shelf wells, (more variable than Gulf Coast tertiary/U.C.) need to evaluate lithology factors and bit type factors to modify the drilling equations specifically for the Scotian Shelf. Data scatter is considerable at present.

b. Formation Temperature Gradient - develop methods to normalize both flowline temperature and bottom hole MWD temperature to filter the effects of ambient temperatures, circulation rate, mud additions and transients due to interruptions in circulation.

Evaluate the practicality of maximum reading thermometers used in single shot surveys and wireline temperature logging. Eventually, with the advent and use of new tools, develop geopressure overlays based on improved knowledge of formation temperature gradients.

c. Shale Resistivity and Shale Interval Transit Time - develop procedures to improve the quality and quantity of data available while drilling. Evaluate the practicality of the following:

- More frequent use of precautionary logs.
- MWD measurements (resistivity and gamma-ray tools are currently available).
- On-site processing of wireline resistivity and sonic logs to provide real-time data for improved detection and prediction/confirmation.
- Develop Scotian Shelf specific overlays for normal and geopressure trends.

Once Scotian Shelf overlays are developed, these may be used to quantify how much of a mud weight increase may be required while drilling through the upper geopressure section to reduce the magnitude of potential kicks. Overlays may also be used for selection of preferred casing setting depths.

d. Vertical Seismic Profiling (VSP) - evaluate the potential of the VSP tools currently available to enhance conventional seismic pressure prediction techniques. Develop methods to obtain reliable sonic logs onboard the rig in advance of entering potential geopressured sections.

3.0 SUMMARY

3.1 Comparison of Detection Parameters

The following table summarizes the relative effectiveness of the conventional parameters in detecting the trend to abnormal pressure before it was confirmed by drilling into a permeable zone.

Comparison of Detection Parameters

Indication Prior to Start of Geopressure Cumulative Percentage

	Parameter	Good	Fair to Good	Poor to Good	No Indication
1.	Connection/ Trip Gas	61%	61%	83%	17%
2.	D Exponent	11%	44%	72%	28%
3.	E Logs	22%	33%	44%	56%
4.	Shale Density	6%	17%	28%	72%
5.	Penetration Rate	0%	11%	22%	78%

Flowline Temperature (not analysed in detail. Data as plotted "real time" by majority of mudloggers is not useable for meaningful interpretation of start of transition zones. Further analysis would be needed to normalize the temperature data.)

3.2 Rating Method

Good: The single parameter provided sufficient indication to detect the abnormal pressure.

Fair: The change in the parameter is recognizable, but an additional indicator is required to adequately detect the pressure change.

Poor: The parameter changes only slightly or over too short an interval such that two or more additional indicators are required to detect the abnormal pressure.

None: No change is observed in the parameter prior to confirming abnormal pressure.

3.3 D Exponent

Plots of this variable indicate that deviation from a "normal" trend can occur as an abrupt shift or change in slope. The abrupt shift is recognizable over 100 m or less, but the slope change may require 300 m or more before it is identified.

3.4 Penetration Rate

This variable was plotted to detect increased penetration rate in transition zones as the bottom hole condition changes from overbalanced to underbalanced drilling with increasing formation pressure. From wells examined, it appears that a recognizable trend (200 m or more) occurs rarely. Short, 2 to 5 m, drilling breaks were not evaluated as these are usually caused by lithology changes from shale to sand, or increased porosity, rather than underbalance. In transition zones of reasonably uniform shales, penetration rate increases should be detectable, assuming constant mud weight, WOB and RPM, but variation in these parameters or inconstant lithology can mask a shift.

3.5 Shale Density

Infrequent data collection and data scatter made it difficult to establish a "normal" trend in shale density. Other overpressured drilling areas report decreasing shale density in transition zones, but if data is not meticulously and regularly taken and analyzed, little can be expected from monitoring this factor.

3.6 Connection/Trip Gas

By quality criterion listed earlier in this section, increases in these factors proved to be the most reliable indicator of overpressure. However, increases in bottom-up gas may be well in advance (as much as 1100 m) of confirmed overpressure. Lithology has a major bearing on the reliability of this indicator, as drilled gas (gas liberated from cuttings from normally pressured sections) may mask this variable.

3.7 Electric Logs

Resistivity and sonic interval transit time (ITT) plots in shale sections are another highly reliable indicator of overpressure. But success of these as warning of impending overpressure is highly dependent on where the logs are run. If the particular log is run over a transition zone, some detectable shift in resistivity or ITT would be expected. If run above the transition zone, little should be expected.

Measurement while drilling (MWD) sensors are available that will acquire resistivity data as the well drills. Most Scotian shelf MWD operations have used more basic directional survey packages, due to higher cost and lack of reliability of the more sophisticated sensor packages. The real time nature of MWD resistivity makes it much less subject to change than electric log runs. No MWD resistivity data is included in the report.

3.8 Flowline Temperature

Because of factors such as riser length, water temperature, circulating rate variations, and others, flowline temperature was not found effective in detecting abnormal pressure.

MWD instruments frequently include a bottom hole temperature sensor, which may be included as an added cost option. No data from this source is included. However, its real time nature and sensor location, which eliminates or reduces the effect of masking factors listed above, gives it higher potential than flowline temperature monitoring.

4.0 SCOPE OF WORK

4.1 Introduction

The area of interest in conducting the abnormal pressure detection study is the sedimentary basin in the vicinity of Sable Island. The basin is bordered to the north and northwest by a high Jurassic carbonate shelf.

Toward the south and southeast, the carbonate formation drops sharply and is overlaid with sand and shale sediments (see Figures 1 and 2).

In section, the basin consists of prospective interbedded sands and shales starting with the relatively shallow Logan Canyon through to the Mississauga/Mic Mac formations. The Logan Canyon and the upper part of the Mississauga are normally pressured. The lower section of the Mississauga on the other hand is the first formation where geopressures are encountered. The transition zones occur across relatively small intervals and contain gradually increasing pressured sands or thin sharply increasing high pressured intervals. The sharp transition zones are associated with thin carbonate beds which are expected to be acting as impermeable seals.

The Mississauga formation continues at high pressures to the Verrill Canyon formation which contains shale and usually defines "total depth" of exploration wells.

The characteristics of the geopressured sections are as follows (references 2, 3, 4 and 5):

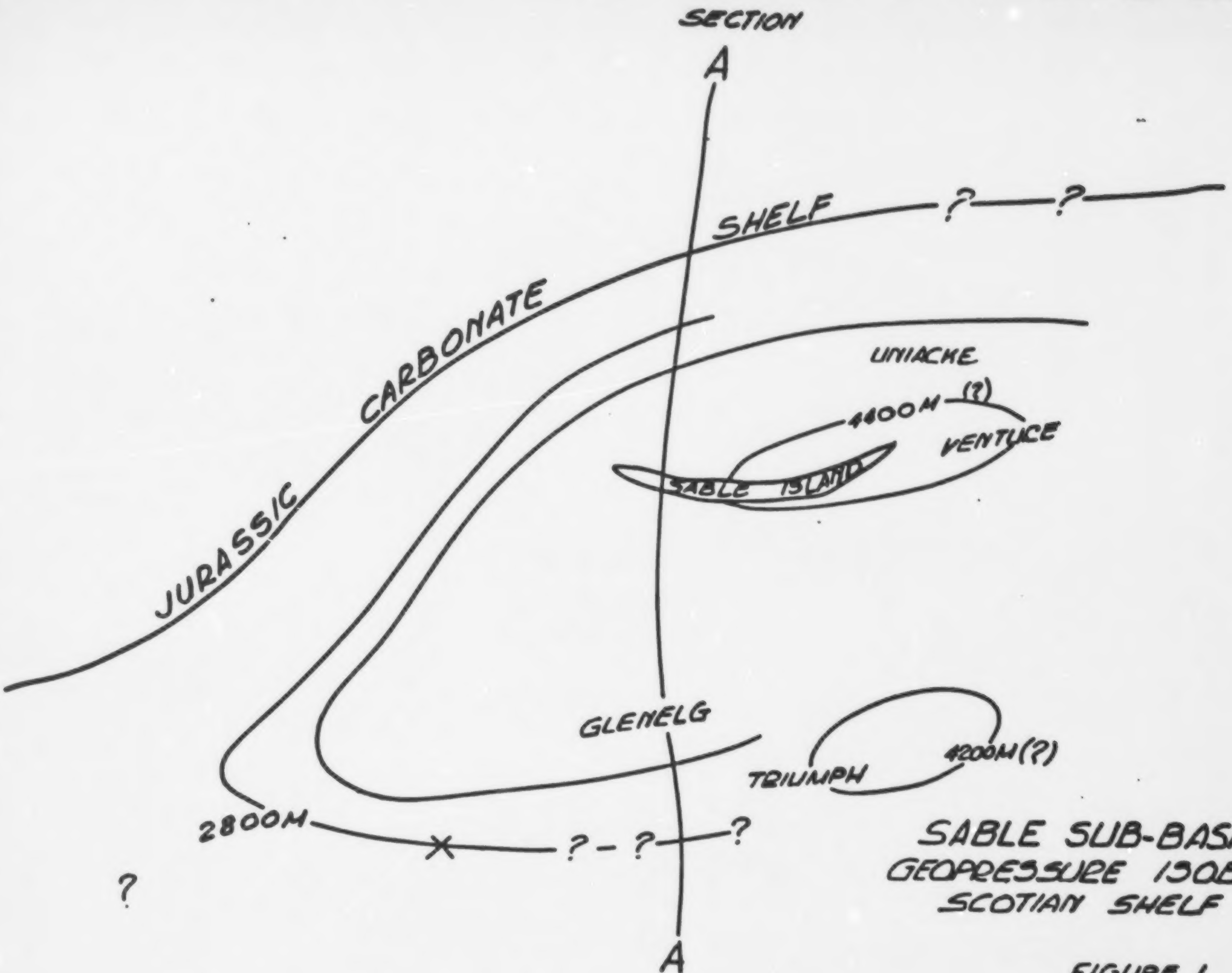
- The top of the geopressures cannot be identified by surface seismic data.
- Deep transition zones can occur in relatively small basin depressions such as at Venture well locations.
- Geopressures are unusual insofar as they occur in a sequence with high ss/sh (sand to shale) ratios.
- Sharp transition zones appear associated with carbonate marker beds.
- Porosities are abnormally high.

- Geopressures register on the sonic log when they are in excess of 0.8 psi/ft.
- Water salinities in the geopressured shales are unusually high at levels of 140,000 ppm.
- Clay transformation (i.e. smectite to illite) does not occur in the geopressured intervals but well above them (about 1500 m).

These characteristics are generally unusual for a geopressured basin where rapid deposition of the sediments is the predominant cause of the high pressures such as in the Gulf of Mexico. In this region, for example, geopressures are more gradually encountered over considerably longer transition intervals due to upward leakage through shale seals. Variations however are found at faults where seals may be less permeable leading to sharper transition zones. Other differing characteristics of the Gulf coast's abnormally pressured sediments are such that:

- They can be identified by seismic.
- They occur in sediments with low ss/sh (sand to shale) ratios.
- They are not associated with carbonate beds.
- Porosities in the geopressured sections are lower than in normally pressured intervals.
- Water salinities are low.

These differences lead to the expectation that different or more specific approaches need to be taken in predicting the onset of geopressures on the Scotian Shelf over those that have so far been suitable for the Gulf of Mexico.


SECTION
A
SHELF
?
?
CARBONATE
JURASSIC
UNIACKE
4400M
(?)
VENTURE
SABLE ISLAND
GLENELG
TRIUMPH
4200M(?)
2800M
? - ?
?
?
A

SABLE SUB-BASIN
GEOPRESSURE ISOBARS
SCOTIAN SHELF

FIGURE 1

SECTION A-A
SABLE SUB-BASIN
SCOTIAN SHELF

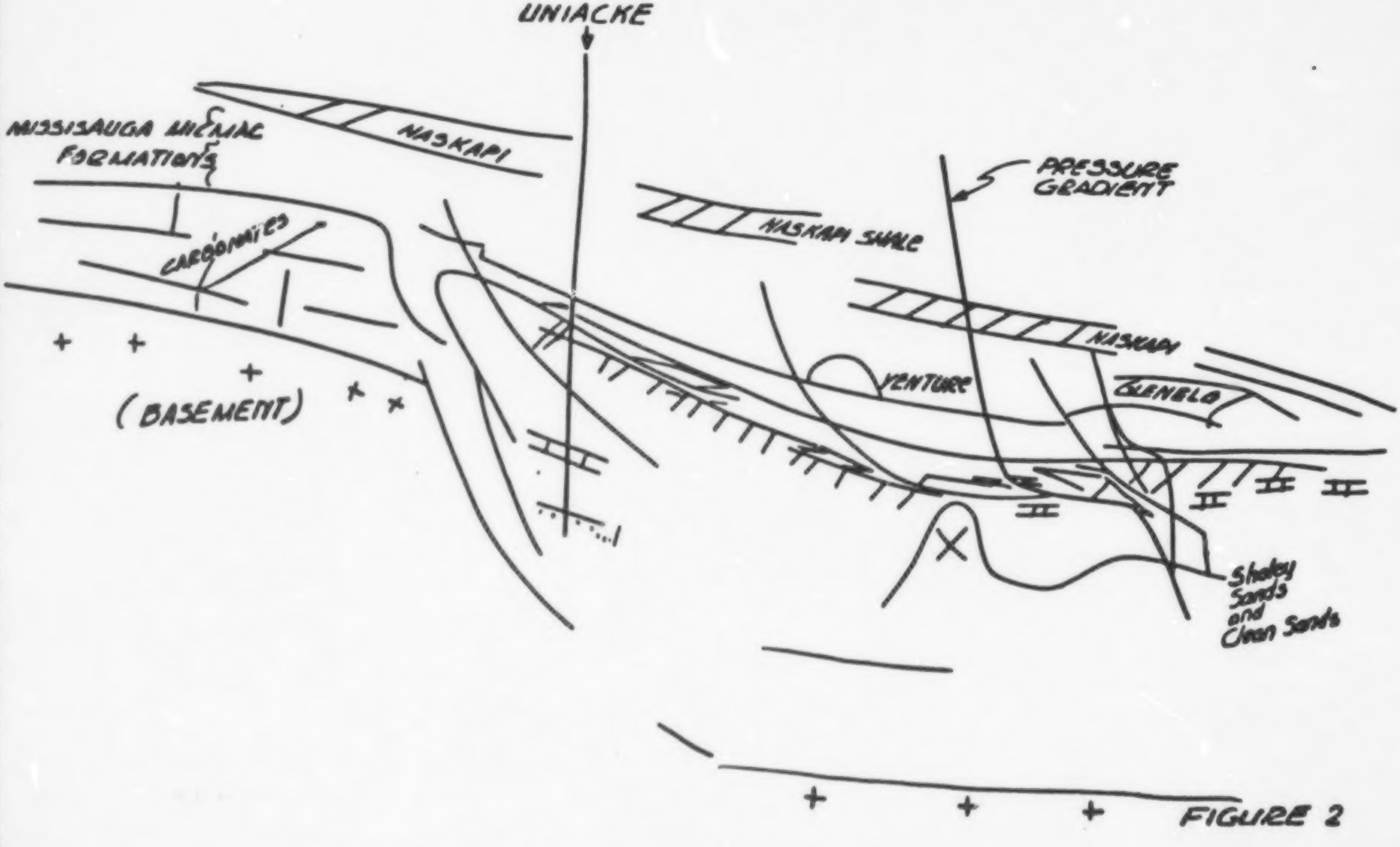

UNIACKE
NASKAPI
MISSISAUGA MICMAC FORMATIONS
CARBONATES
(BASEMENT)
NASKAPI SHALE
PRESSURE GRADIENT
NASKAPI
VENTURE
GLENELG
Shaley Sands and Clean Sands

FIGURE 2

4.2 Study Objective

The letter from the C.P.A. Task Force outlines the objective of the study. It requires that the study "-- provides guidance and advice to operators in the selection, correction and presentation of real time drilling data that will provide reliable early warning of the presence and magnitude of abnormal pressures.--" This is needed because "-- there remains a high incidence of taking relatively large kicks in the pressure transition zones due to the difficulty in predicting -- the environment --" ahead of the "bit".

In thinking through this objective, the geology and lithology of the Scotian Shelf suggests that the study will likely conclude that the method of predicting changes in geopressures will probably require an incremental evaluation and detection process that first starts with the need for an understanding of geopressures on a regional basis. It will be necessary to progress through a series of procedures while drilling including physical data acquisition over small intervals, followed by manipulation and interpretation of the detection parameters. This approach could take the form of two major steps:

1. Identifying the risk intervals of an early stage so that they can be inserted in the drilling prognosis for the well.
2. Conducting a series of procedures on the drilling rig that are triggered by a rank order list of detection parameters from recognizable conditions as the risk intervals are drilled.

So far, the techniques available to industry are to use the following six major sources of data (Reference 1).

1.	Geophysical Methods	Carried out through seismic operations prior to spudding a well. Seismic data is not so far a suitable technique for the Scotian Shelf.
2.	Drilling Parameters	Monitored while drilling.
3.	Drilling Mud Parameters	Monitored while drilling but delayed by the time required for mud returns.
4.	Shale Cuttings	Monitored while drilling but delayed by the time required for mud returns.
5.	Logging Tools	Mainly carried out after drilling long sections of the well, consequently on-coming short interval geopressured sections may not be predictable with logging tools.
6.	Direct Pressure	Carried out after drilling through the Measurement use of R.F.T.'s and physical well tests.

Of the six sources of data, "Drilling Parameters" (while drilling) most likely will have the best chance of providing prediction and detection techniques on Scotian Shelf wells. Four of the commonly used parameters include:

1. Penetration rate which normally increases in shales with increasing geopressures. However, if a limestone layer associated with sharp geopressures is penetrated, the penetration rate may reduce through the layer, then dramatically increase with the high pressures are encountered. The trend in normally pressured sands and shales is a reduction in penetration rate with depth.
2. Calculation of a "d" exponent or a modified "d" exponent or "dc" which "normalizes" the penetration rate into a dimensionless number. The "d" or "dc" exponent recognizes variations in rotary speed, weight on bit, bit size and actual mud weight.
3. Surface measured conditions with various delays in time such as gas content in the mud, mud temperature, shale density, logging runs, R.F.T.'s and well tests.

Further than this, drilling rate equations can be used to establish correlations between bore hole and formation pressures, however they are complex to use and do not account for lithological changes.

All of these parameters can be expected to predict trends, however, the nature and complexities of the Scotian Shelf lithology and geopressures suggest that:

1. Geopressures can occur too quickly to count heavily on the normal approach to monitoring drilling parameters, logging a well, or monitoring mud gases or mud temperatures.

2. Since sharply increasing geopressures are associated with carbonate seals, the "d" exponent in its present form may not be suitable since it does not recognize lithological changes (reference 1).

4.3 Work Outline

At this time and from data so far reviewed, it is expected that the future ability of detecting transitional pressures in a geopressured zone is more than likely going to lean heavily on adequately monitoring and interpreting "real time" data while drilling the well. Consequently, the methodology as outlined in the C.P.A. Task Force letter suggesting that "-- preparing a historical analysis of drilling data from wells -- will identify parameters that reliably indicate the onset of the geopressure transition zone" is necessary and can be pursued in the following steps (a list of wells on which analyses are expected to be carried out is outlined in Table 1):

4.3.1 Preparation of Well Plots (Step 1)

This is a preparatory step of plotting the conventional pressure detection parameters on a compressed scale (say 1:10,000) for each well. The procedure should clearly establish normal trends and illustrate relative deviations from the normal provided by each parameter when entering the transition zone. The plotting should be done by the Mud Logging Companies for the wells where they provided services, with EPI plotting the electric log data and preparing the composite plot. The transition zones for which there is adequate documentation will then be examined in more detail (Step 2). In the event that cursory log evaluations or the evaluation of recorded drilling data for particular wells establishes the transition zones without the composite plots on the compressed scale, then this step may be avoided unless the data is needed to compliment the overall study.

4.3.2 Preparation of Geopressured Zone Plots and Analyses (Step 2)

The pressure detection parameters will be replotted on an expanded scale (say 1:600) for each transition zone. The normal trends as identified on the compressed plot will be transferred to these plots. It will then be determined, for each parameter, if there is a significant deviation from the normal trend that could have or did provide a warning of the increasing pore pressure. A significant deviation would be defined as a measured value which is beyond the normal scatter of the data for that parameter. From this analysis, a ranking of the parameters should then be possible.

Plots will also be prepared for drilling parameters over the same interval and on the same scale as the detection parameters. The drilling parameters will be analyzed in conjunction with the D exponent to determine if modifications to the standard D exponent should be progressed. Also, from the ranking of the detection parameters and the relative deviation produced by each parameter, a work outline will be developed for selection of applicable detection techniques.

5.0 METHODOLOGY

5.1 Data Collection

Originally the participating Operators thought that all the required data i.e. well history reports, mud logs, electric log data, etc. would be available to EPI from the COGLA Halifax/Dartmouth offices. In most cases the data is available but COGLA do not permit files to be removed from their offices. In order to collect all the data into the EPI Halifax office it was necessary to rely heavily on the Mud Logging Companies, Nova Scotia Department of Mines and Energy and Schlumberger. Not much data was obtained during the Christmas/New Year period, but by the end of January 1986 sufficient information was available to start data plotting and presentation.

5.2 Detection Data Preparation/Presentation

The source data from the mud logging companies, well history reports and electric wireline logs was plotted on a common scaled spread sheet. This was necessary in order to make direct comparisons between the wells being studied.

Compressed scale plots (approximately 1:12,000) were prepared for each of the 19 wells, including the following parameters: (1) lithology; (2) d exponent; (3) shale density; (4) penetration rate; (5) mud weight; (6) confirmed formation pressures from RFT's/DST's; (7) tip/connection gas; (8) resistivity log data; and (9) sonic log data.

A true depth scale (RT) was used for all the plots. In order to protect well identity, each well was numbered in sequence 1 to 19. For 7 of the wells an expanded scale plot (approximately 1:4,000) was made for the geopressured section of the well.

Notes have been made directly on the data sheets where particular data was missing or not available to EPI.

The flowline temperature data "as presented" by the mud logging companies could not be utilized unless additional analysis of the data was done. As time did not permit this during the Phase I of the study, flowline temperature data was not plotted on the individual well spread sheets.

The shale resistivity and shale interval transit times were extracted from the Schlumberger logs by EPI staff. In future, the Operators should request Schlumberger to print out, from magnetic tapes, a complete shale resistivity plot and a shale interval transit time plot for geopressured wells. This can be done at reasonable cost at the time a particular geopressured well is drilled (with appropriate cut-off for shale content).

5.3 Interpretation

Once the common spread sheet plots were completed, each well was "redrilled" examining the detection parameters with depth and determining if each parameter indicated the onset of the start of geopressures before the actual geopressures were encountered. Most of the while drilling parameters i.e. "d" exponent, shale density, penetration rate, trip/connection gas, indicated, in varying degrees, some departure from normal trends. In some cases the deviation from normal trends started to occur slightly in advance of increasing pore pressure, and on other occasions the deviations did not occur until the transition zone was entered or the well flowed.

It was not intended, as part of this study, to prepare overlays for each well, and then determine if a composite overlay approach would be applicable to all wells.

The objective of the Phase I was to determine which of the detection while drilling parameters were more useful in decending order of reliability. In order to determine a ranking of the parameters, a subjective approach had to be used. Each detection parameter was rated (for each well) on the basis of whether it was a good, fair, poor or nothing indicator prior to entering the geopressured section. As previously mentioned, several parameters started to show deviations from normal trends only after the geopressured section was entered essentially providing no advance warning (these cases would be rated no indication).

Electric log data, resistivity and sonic, were used to confirm the start of geopressure and to define the geopressured section. Again, this Phase of the study did not develop overlays which may be useful for new well prediction analysis. If the logs were run near the top of a transition zone and could have been used to determine a departure from normal trends, then they were rated as a good indicator. However in most cases wireline logs were not run until a significant portion of the geopressured zone had been entered.

Section 3.0 of this report presents a Summary of the data interpretation.

The Geopressure Drilling Task Force undertook to ensure all well data would remain confidential by normalizing data plotting and disguising its identification. As the presentation of data in this report is not considered to be satisfactorily disguised only those wells that have been released from confidential status as of the date of this report issue are included.

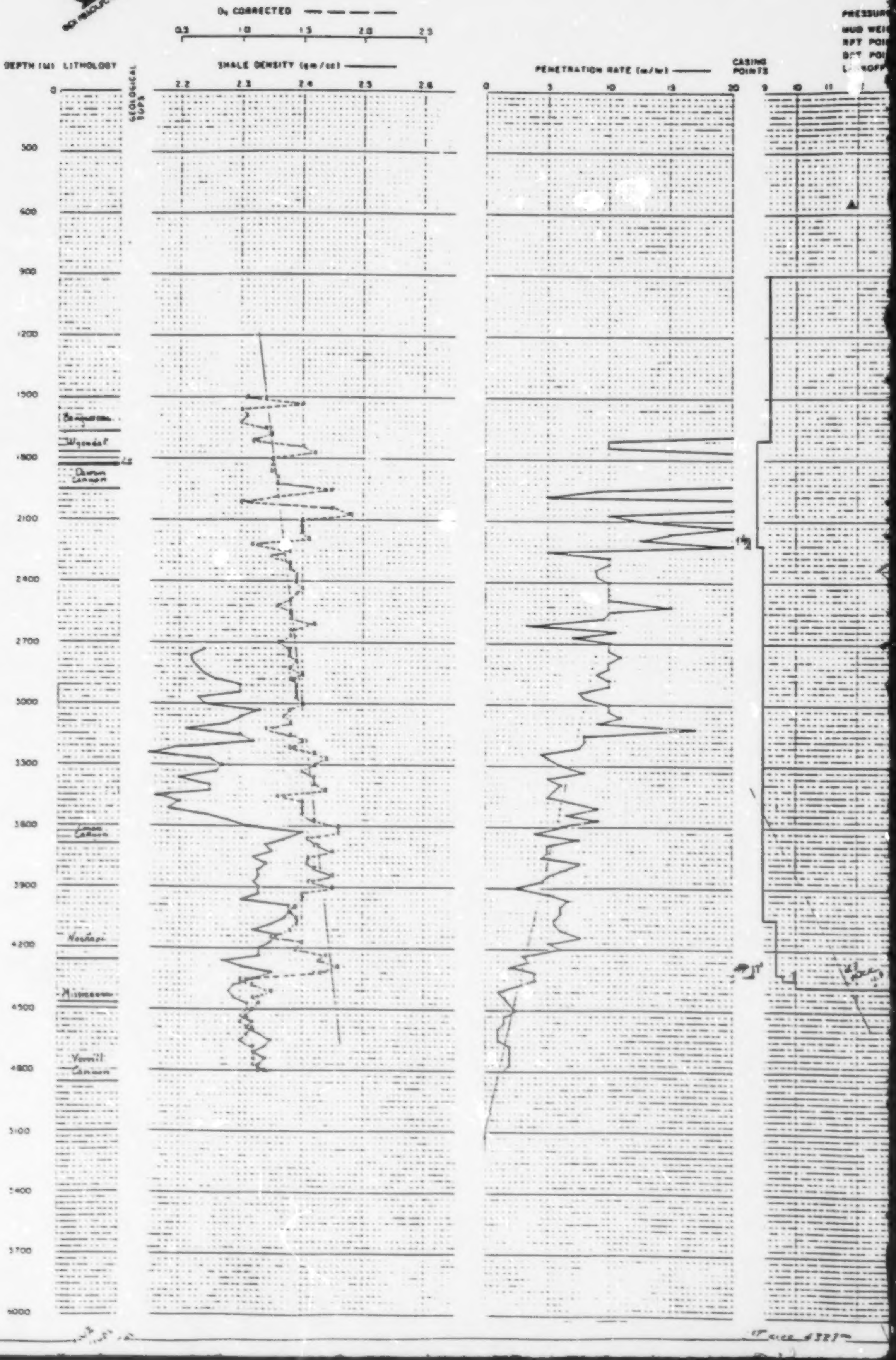
6.0 APPENDIX

6.1 Individual Well Plots

6.2 EPI Working Papers/Notes

PRESSURE EVALUATION LOG

SCOTIAN SHELF GEOPRESSURE EVALUATION
PROJECT No. 059-2



WELL NAME T#1

OPERATOR

SPUD DATE

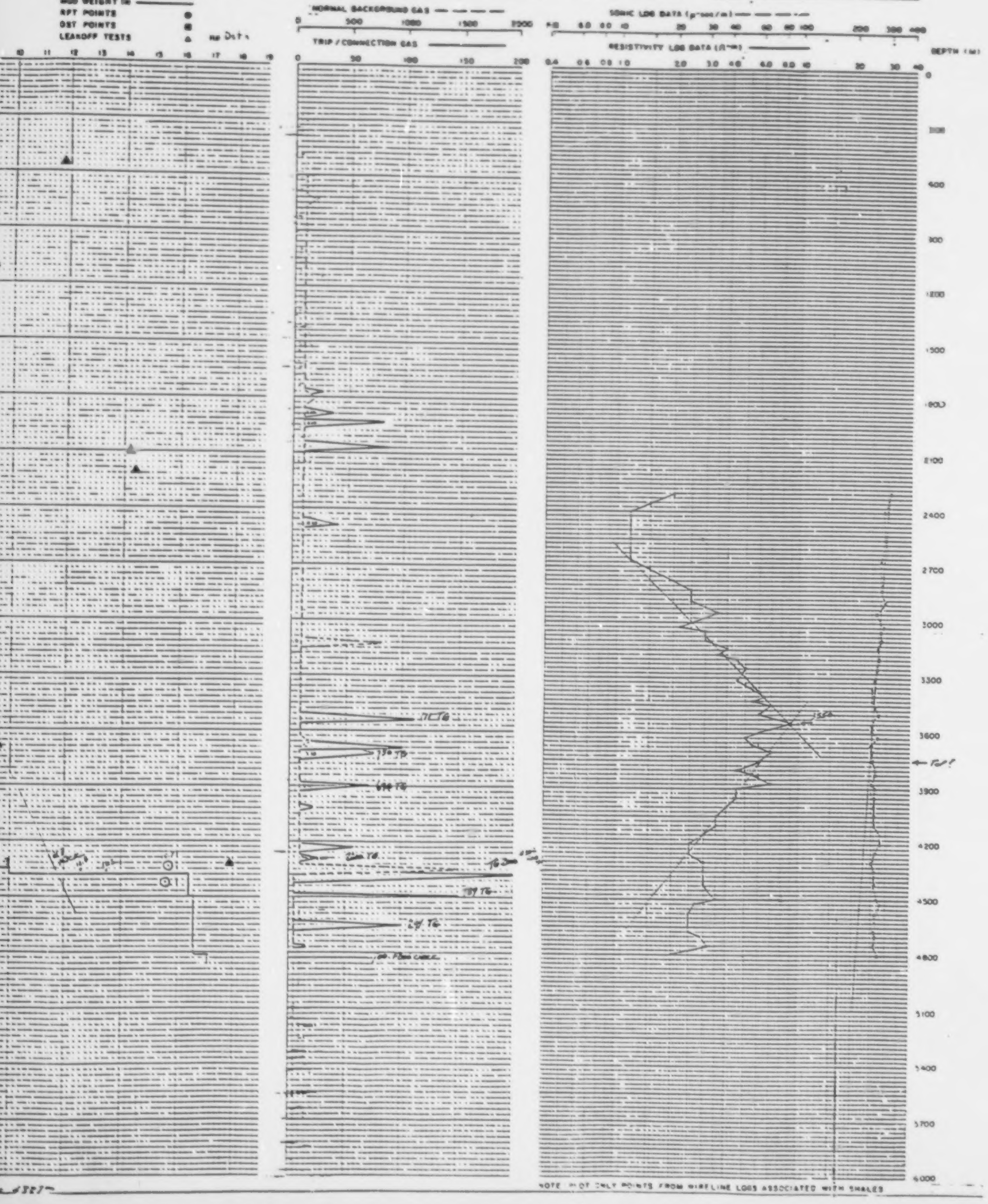
TOTAL DEPTH

RIG NAME

LOCATION ______ N ______ W

COMPLETION DATE

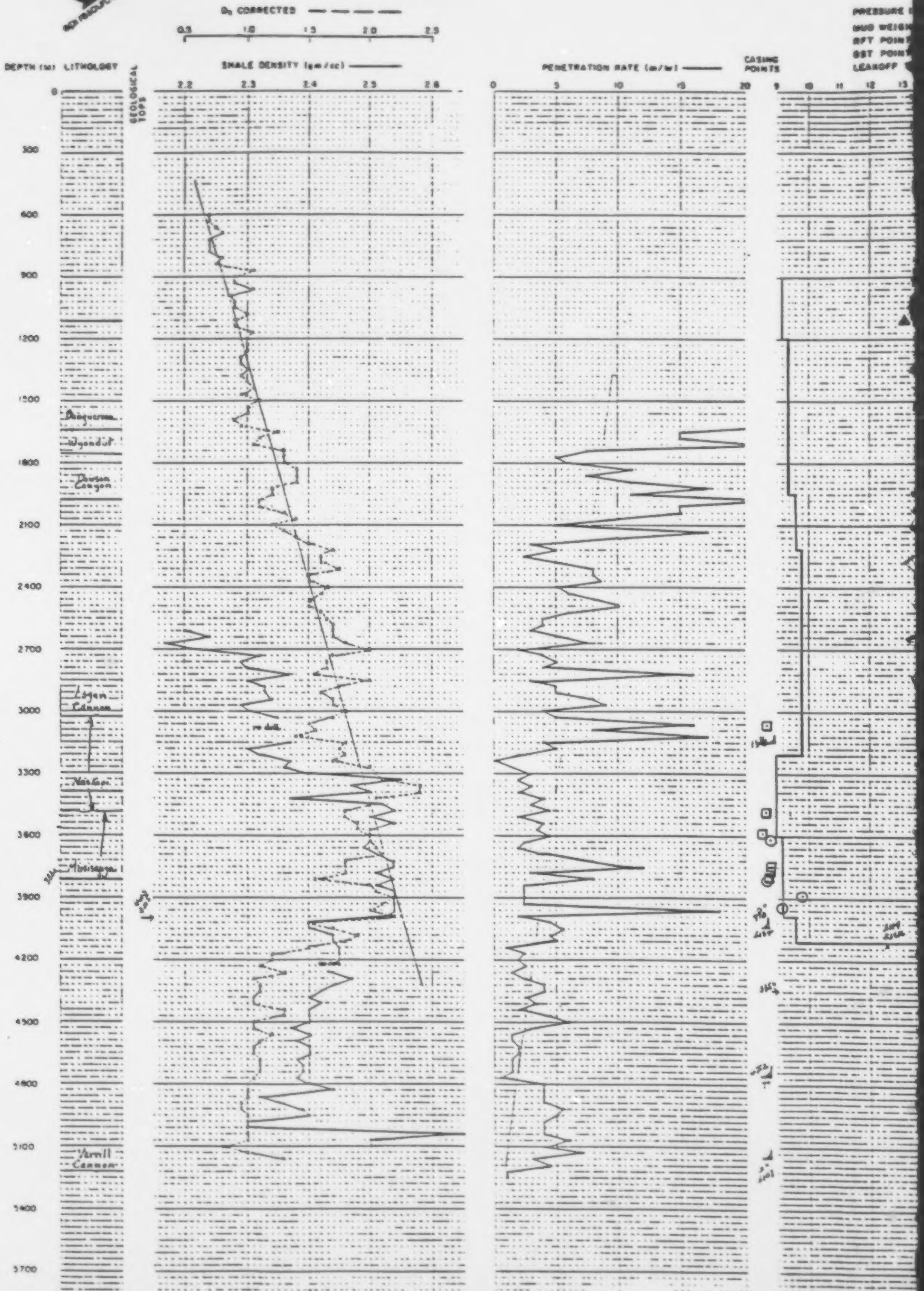
WATER DEPTH



NOTE: PLOT ONLY POINTS FROM WIRELINE LOGS ASSOCIATED WITH SHALES

PRESSURE EVALUATION LOG

SCOTIAN SHELF GEOPRESSURE EVALUATION
PROJECT No. 059-2



WELL NAME (#2

OPERATOR

SPUD DATE

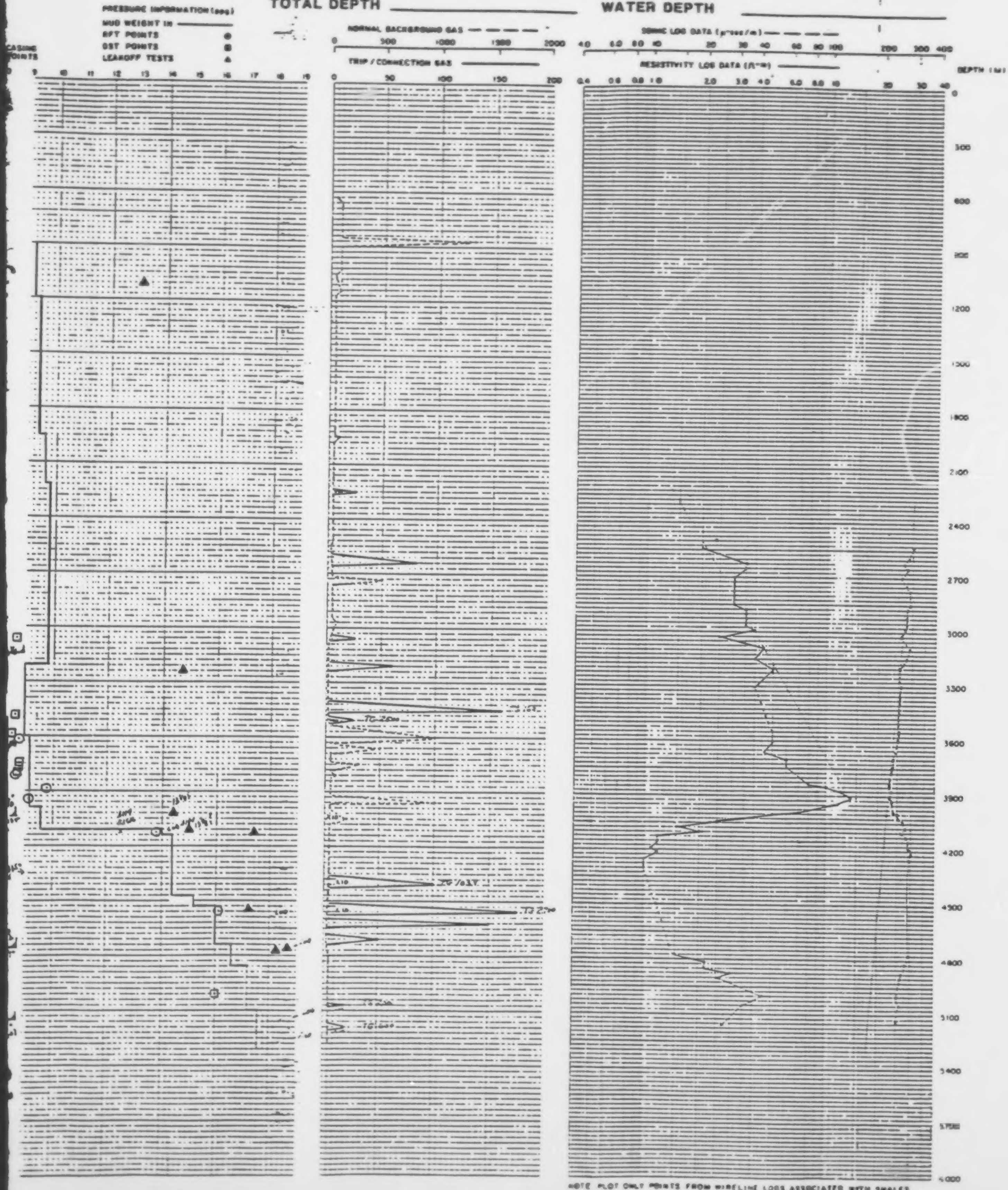
TOTAL DEPTH

RIG NAME

LOCATION N W

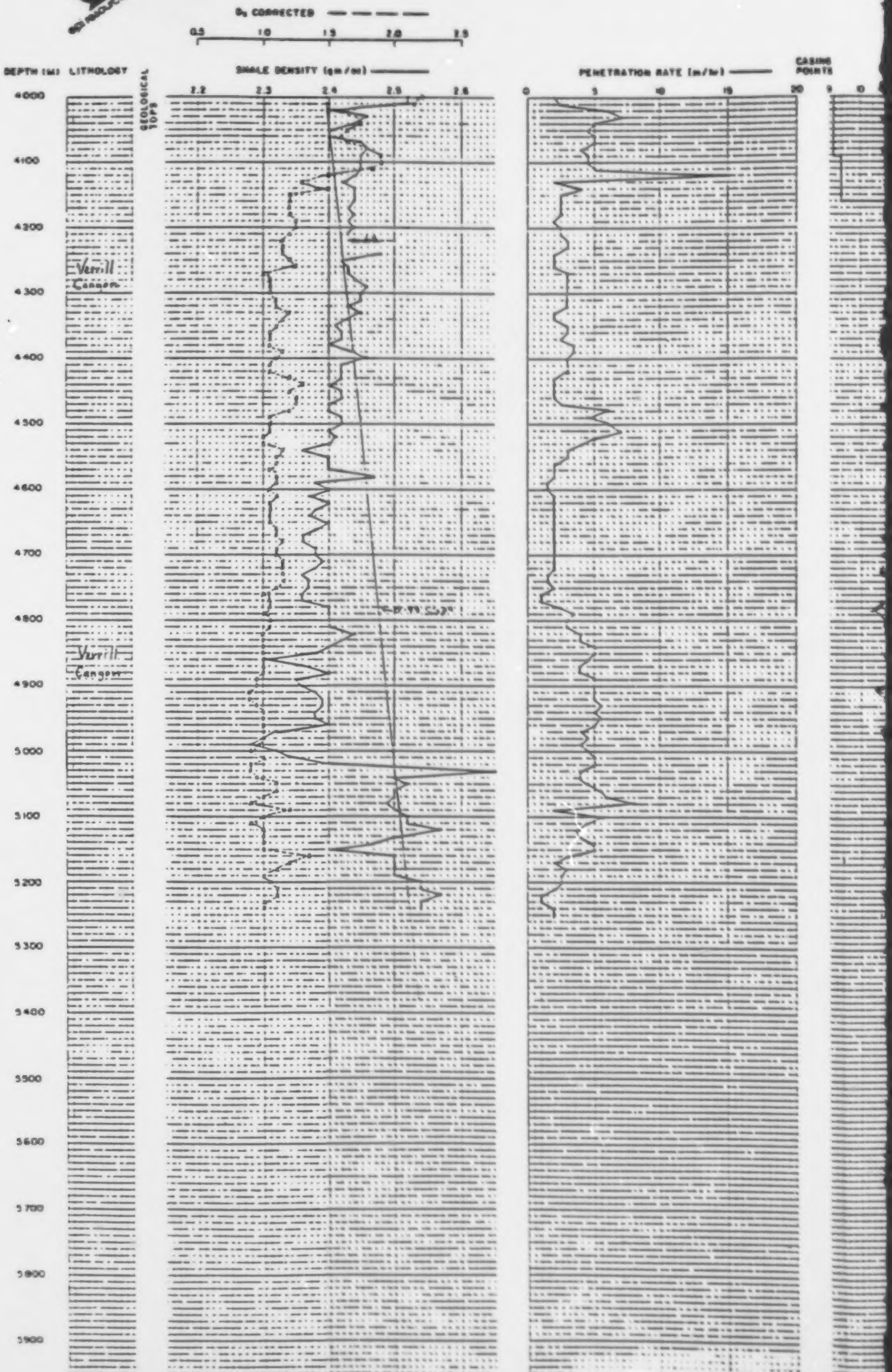
COMPLETION DATE

WATER DEPTH



PRESSURE EVALUATION LOG

SCOTIAN SHELF GEOPRESSURE EVALUATION
PROJECT No. 059-2



G

WELL NAME (#2 Explored

OPERATOR

SPUD DATE

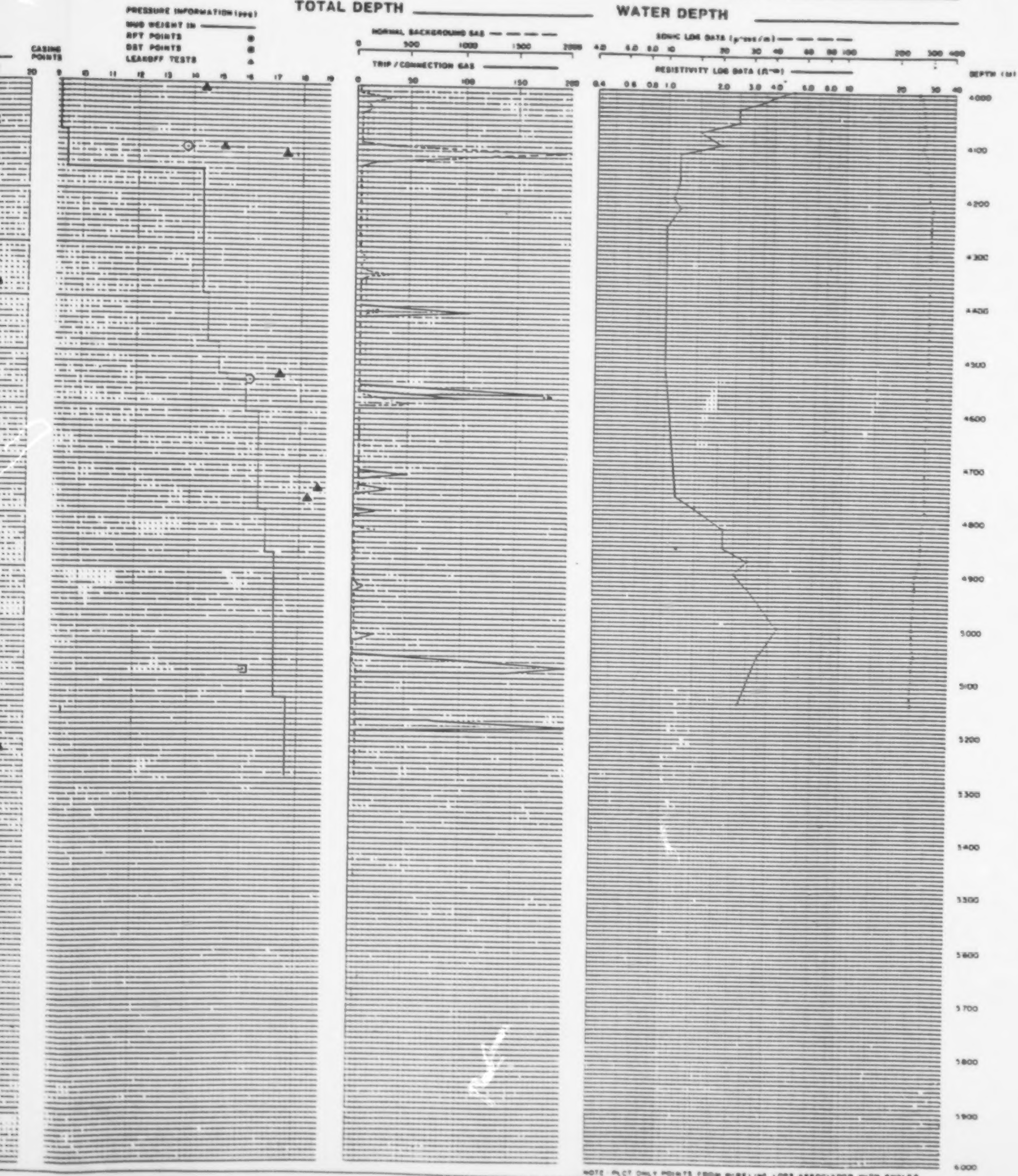
TOTAL DEPTH

RIG NAME

LOCATION ____ N ____ W 92.

COMPLETION DATE

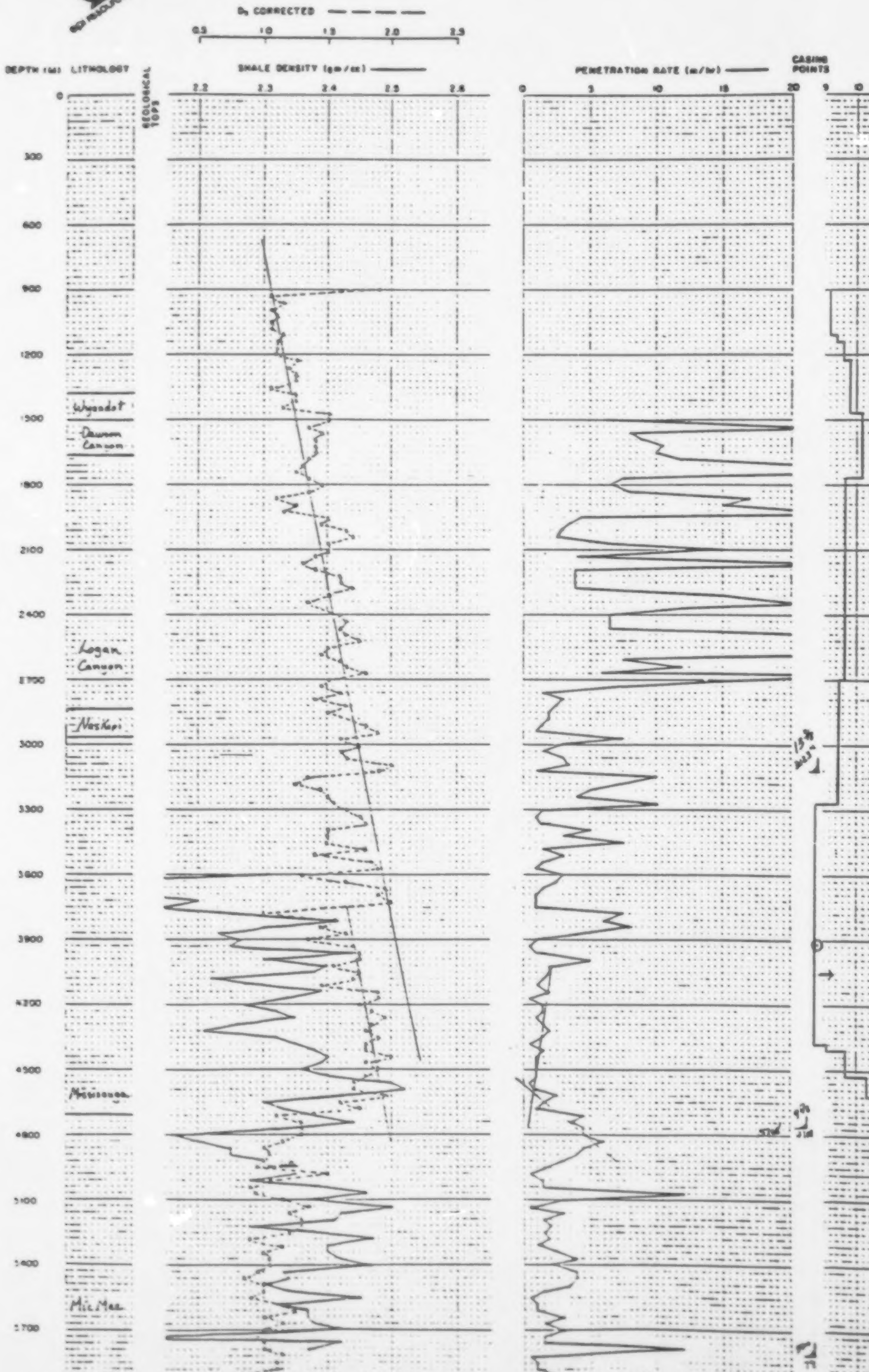
WATER DEPTH



NOTE: PLOT ONLY POINTS FROM WIRELINE LOGS ASSOCIATED WITH SHALES

PRESSURE EVALUATION LOG

SCOTIAN SHELF GEOPRESSURE EVALUATION
PROJECT No. 059-2



G

WELL NAME (#2. Expanded

OPERATOR

SPUD DATE

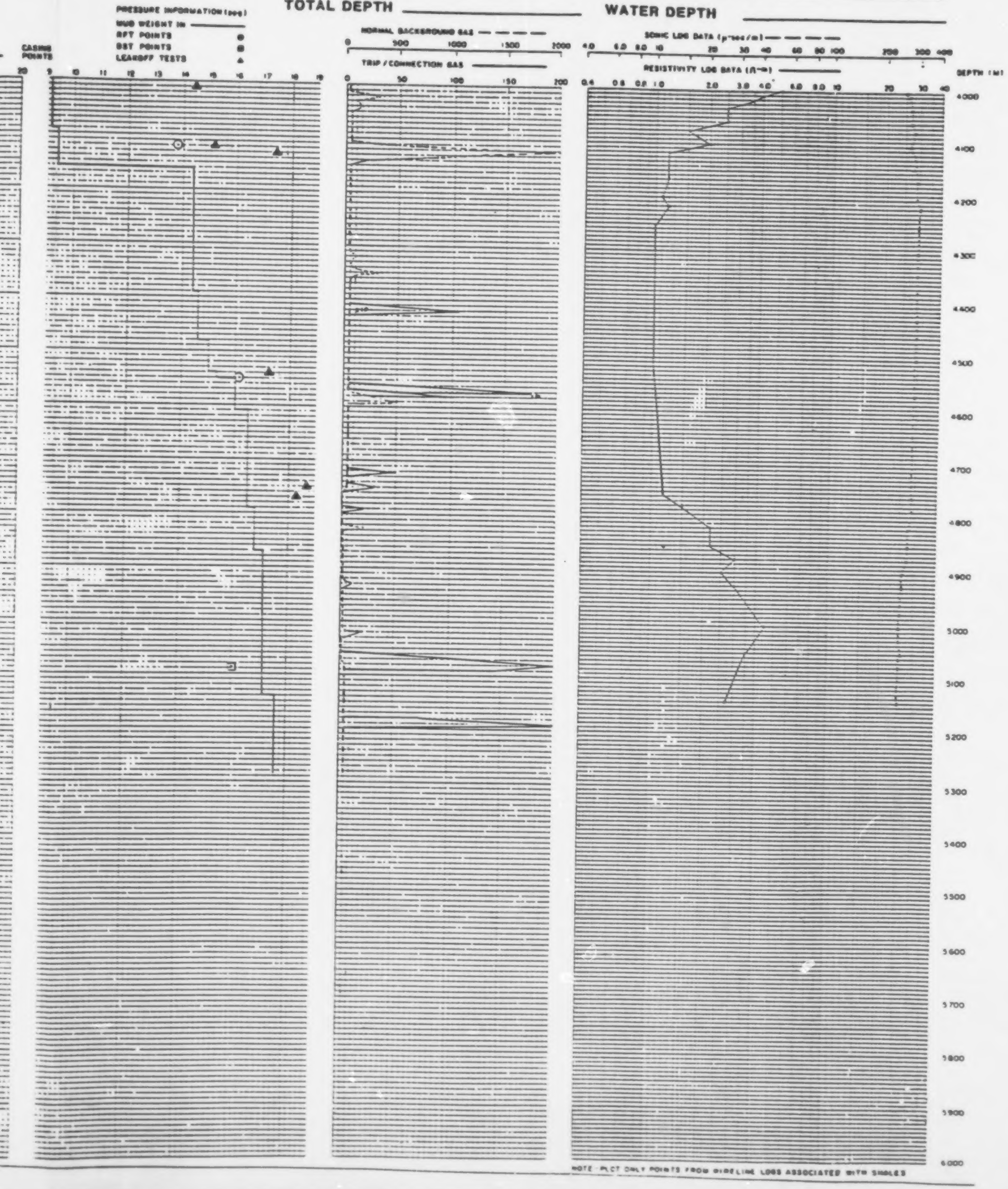
TOTAL DEPTH

RIG NAME

LOCATION ______ **N** ______ **W** 92.

COMPLETION DATE

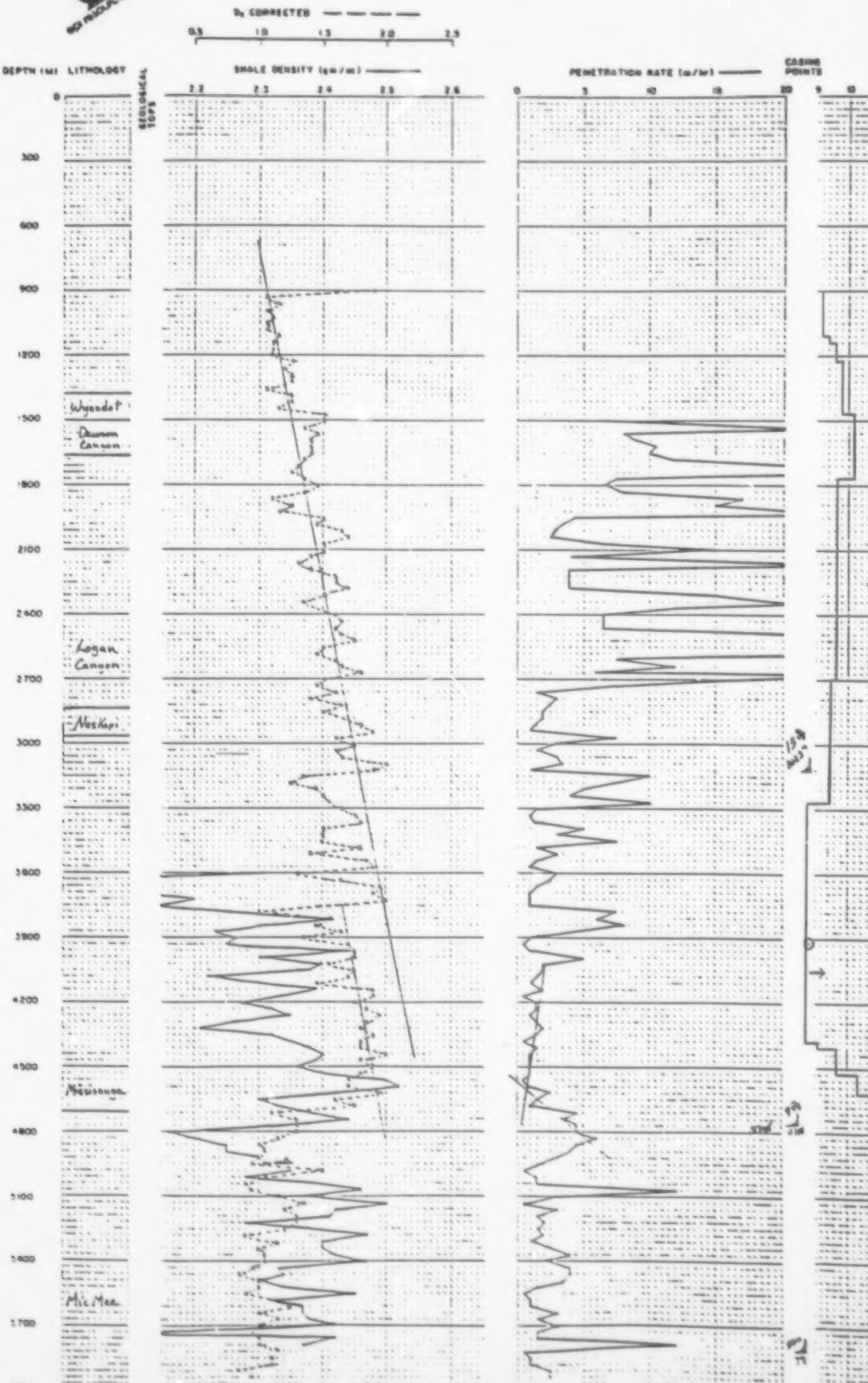
WATER DEPTH



NOTE: PLOT ONLY POINTS FROM WIRELINE LOGS ASSOCIATED WITH SHALES

PRESSURE EVALUATION LOG

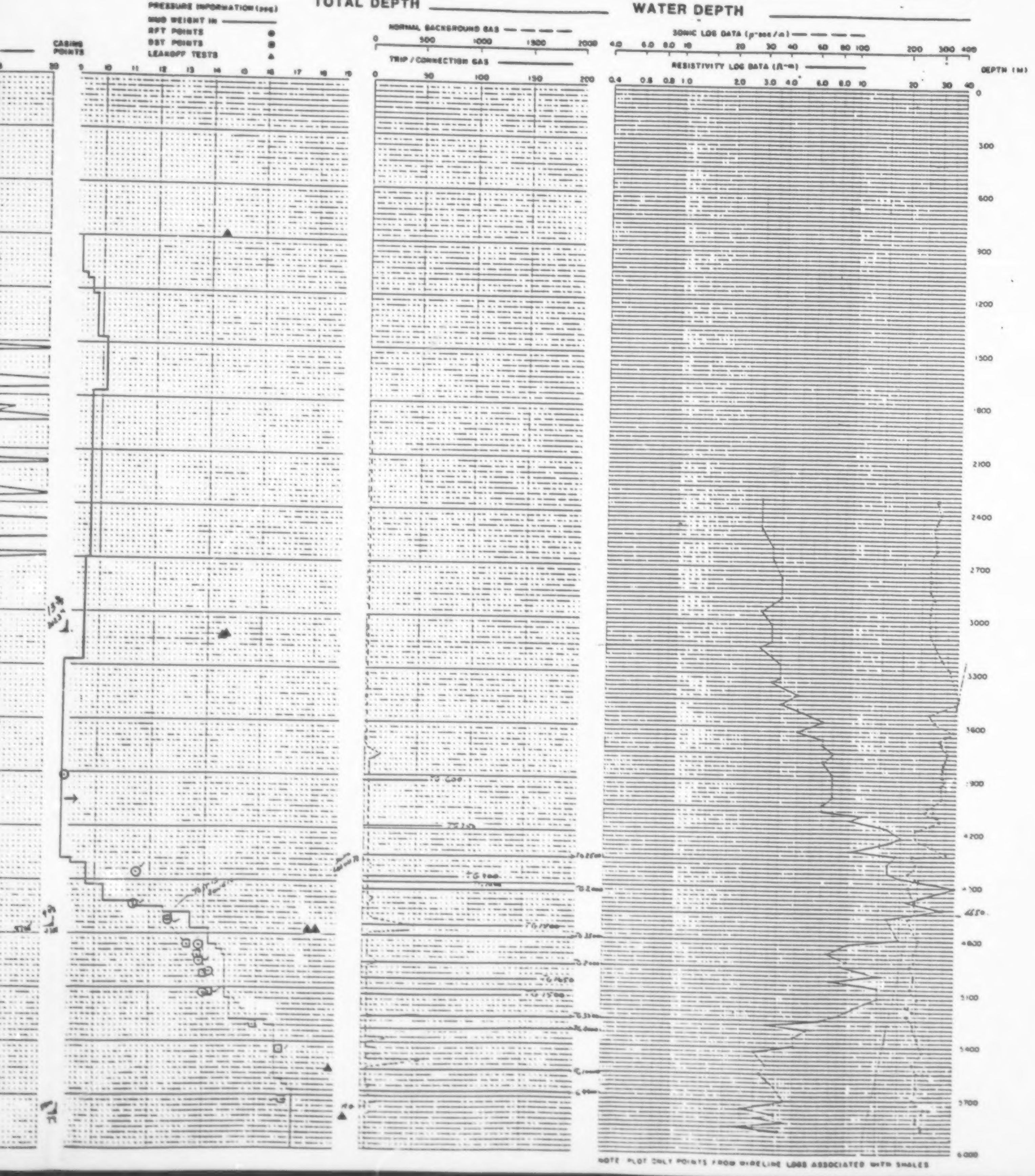
SCOTIAN SHELF GEOPRESSURE EVALUATION
PROJECT No. 059-2



OG

WELL NAME ___#3___
OPERATOR ______
SPUD DATE ______
TOTAL DEPTH ______

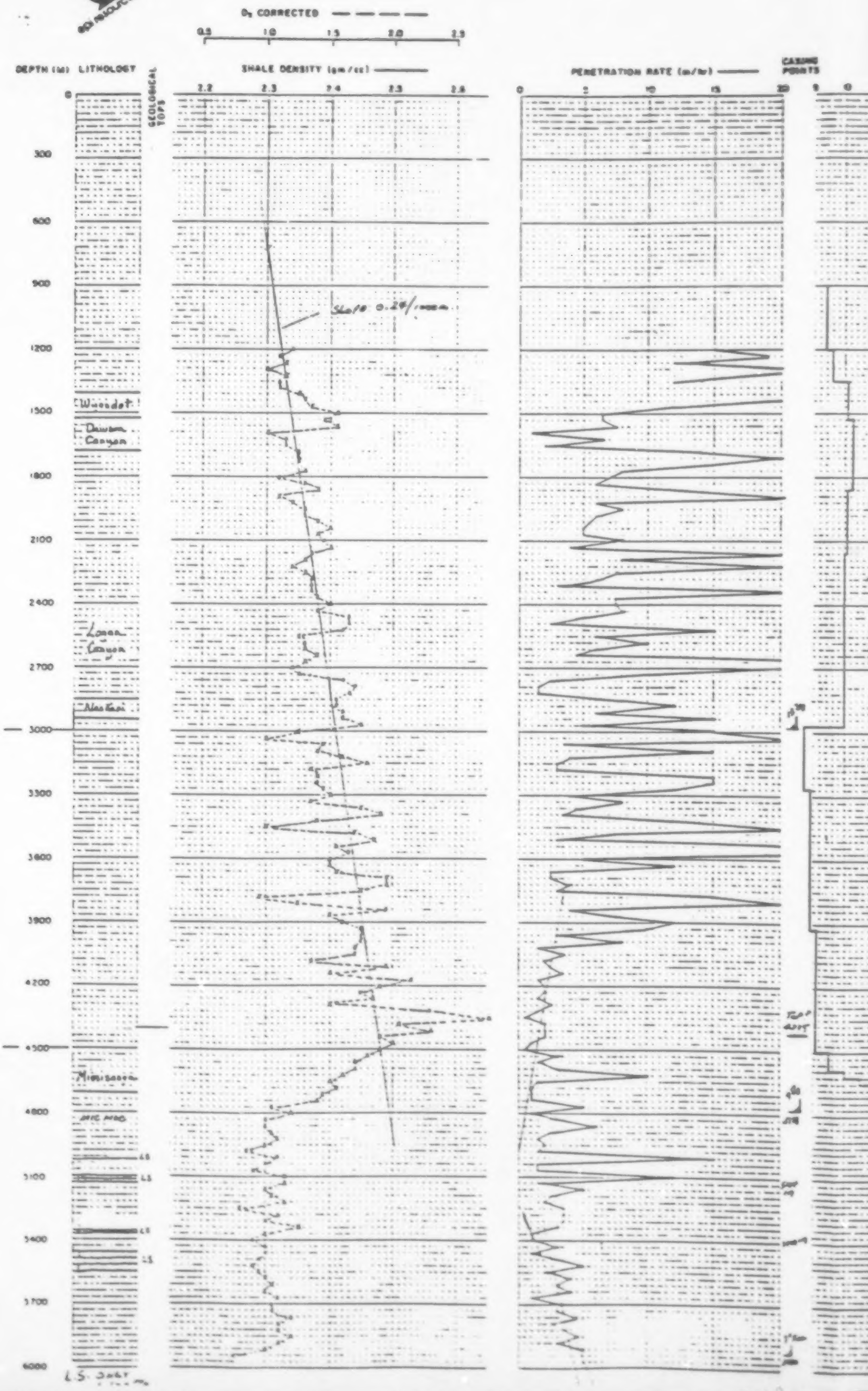
RIG NAME ______
LOCATION ______ N ______ W
COMPLETION DATE ______
WATER DEPTH ______



NOTE: PLOT ONLY POINTS FROM WIRELINE LOGS ASSOCIATED WITH SHALES

PRESSURE EVALUATION LOG

SCOTIAN SHELF GEOPRESSURE EVALUATION
PROJECT No. 059-2



WELL NAME #4

OPERATOR

SPUD DATE

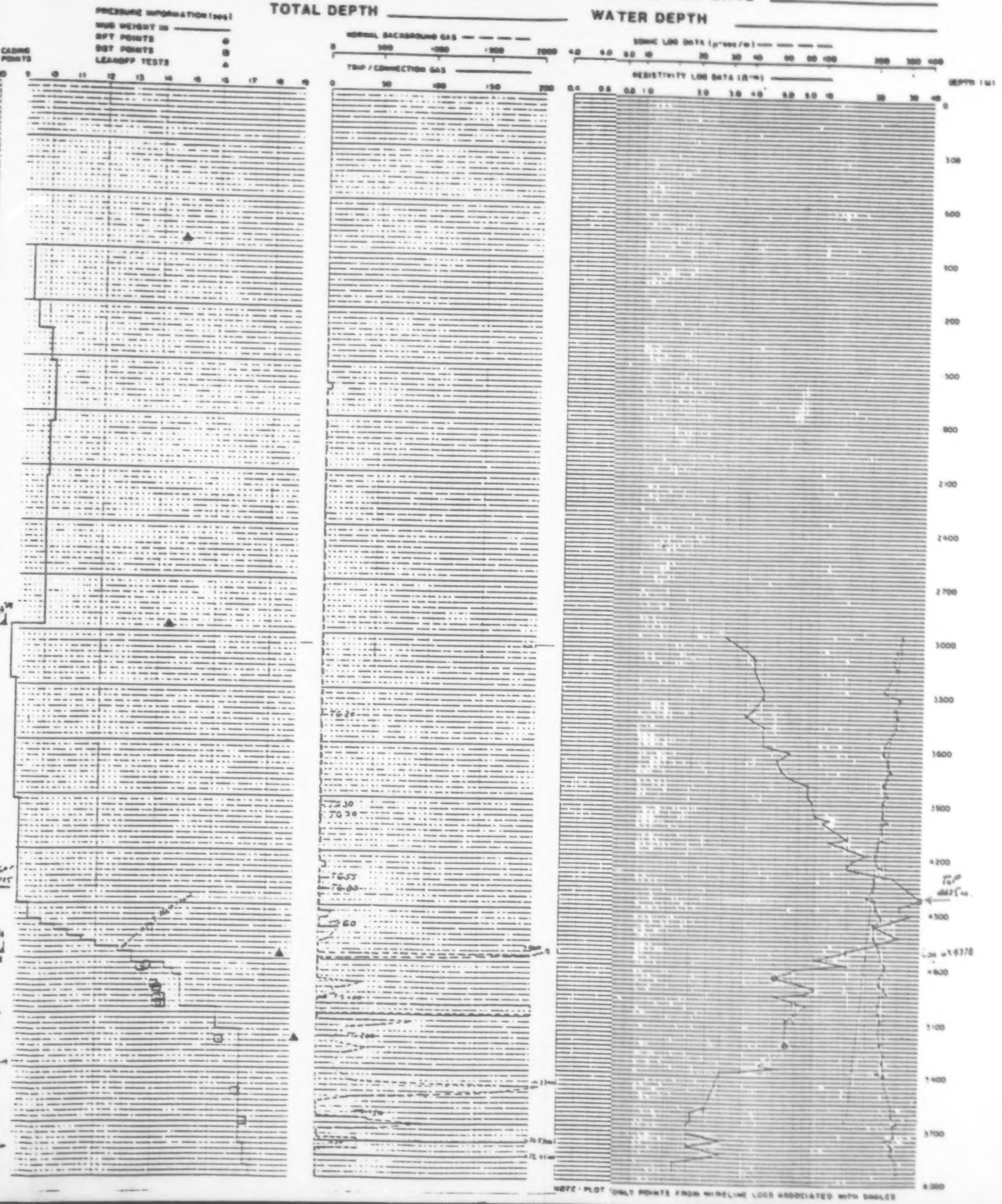
TOTAL DEPTH

RIG NAME

LOCATION N W

COMPLETION DATE

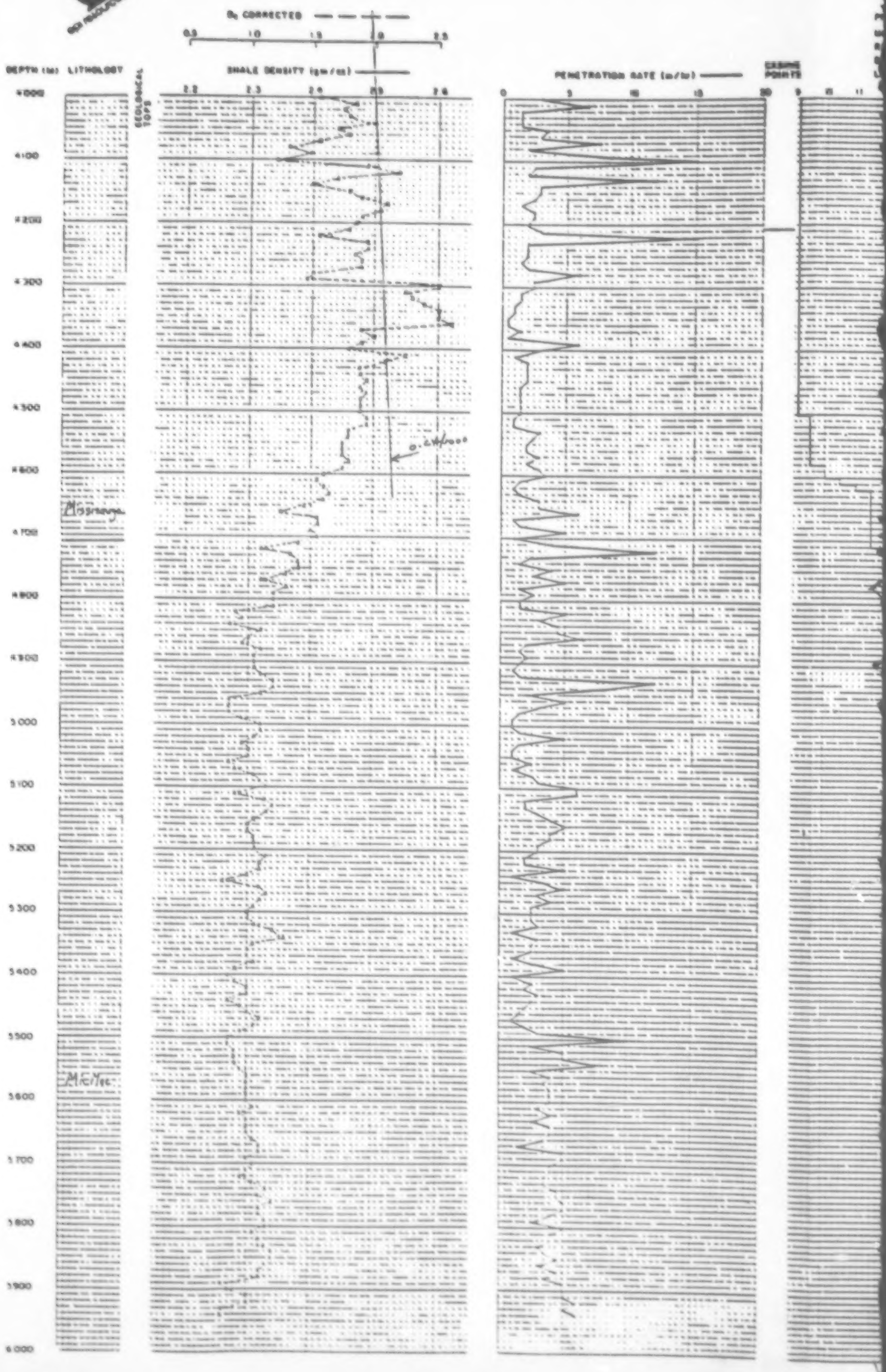
WATER DEPTH



NOTE: PLOT ONLY POINTS FROM WIRELINE LOGS ASSOCIATED WITH SHALES

PRESSURE EVALUATION LOG

SCOTIAN SHELF GEOPRESSURE EVALUATION
PROJECT No. 059-2



OG

WELL NAME #4 Expwood

OPERATOR

SPUD DATE

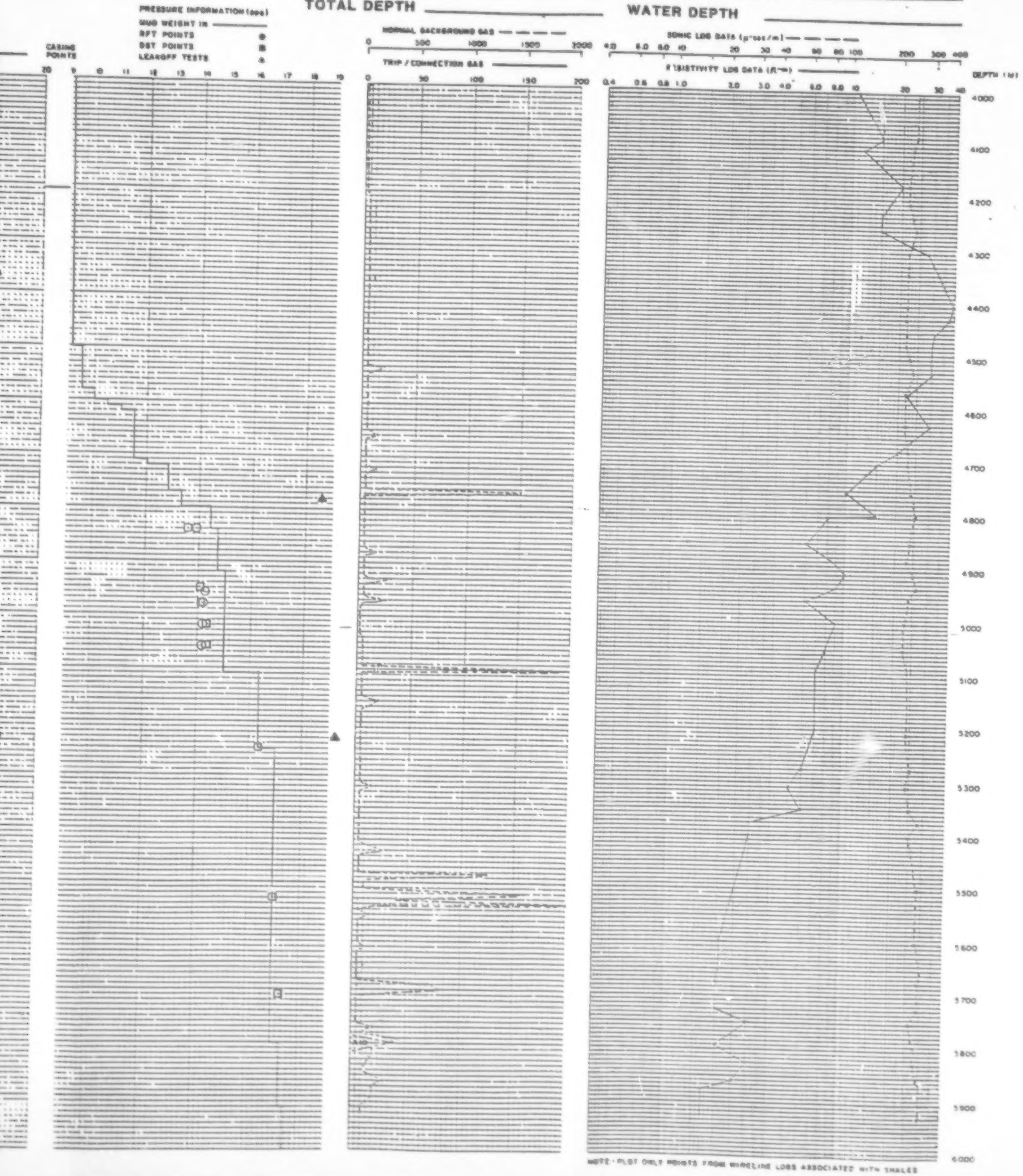
TOTAL DEPTH

RIG NAME

LOCATION N W

COMPLETION DATE

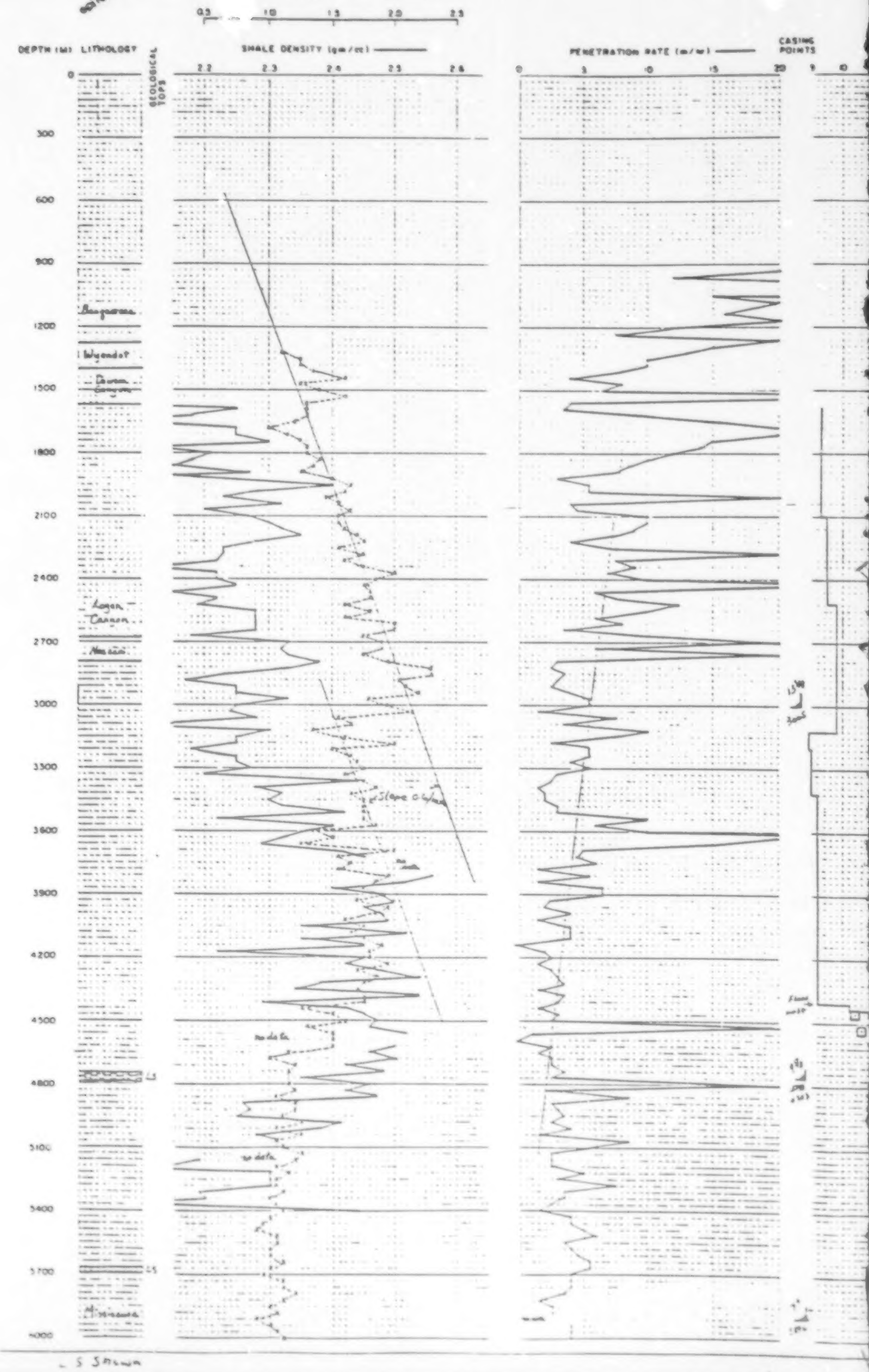
WATER DEPTH



NOTE: PLOT ONLY POINTS FROM WIRELINE LOGS ASSOCIATED WITH SHALES

PRESSURE EVALUATION LOG

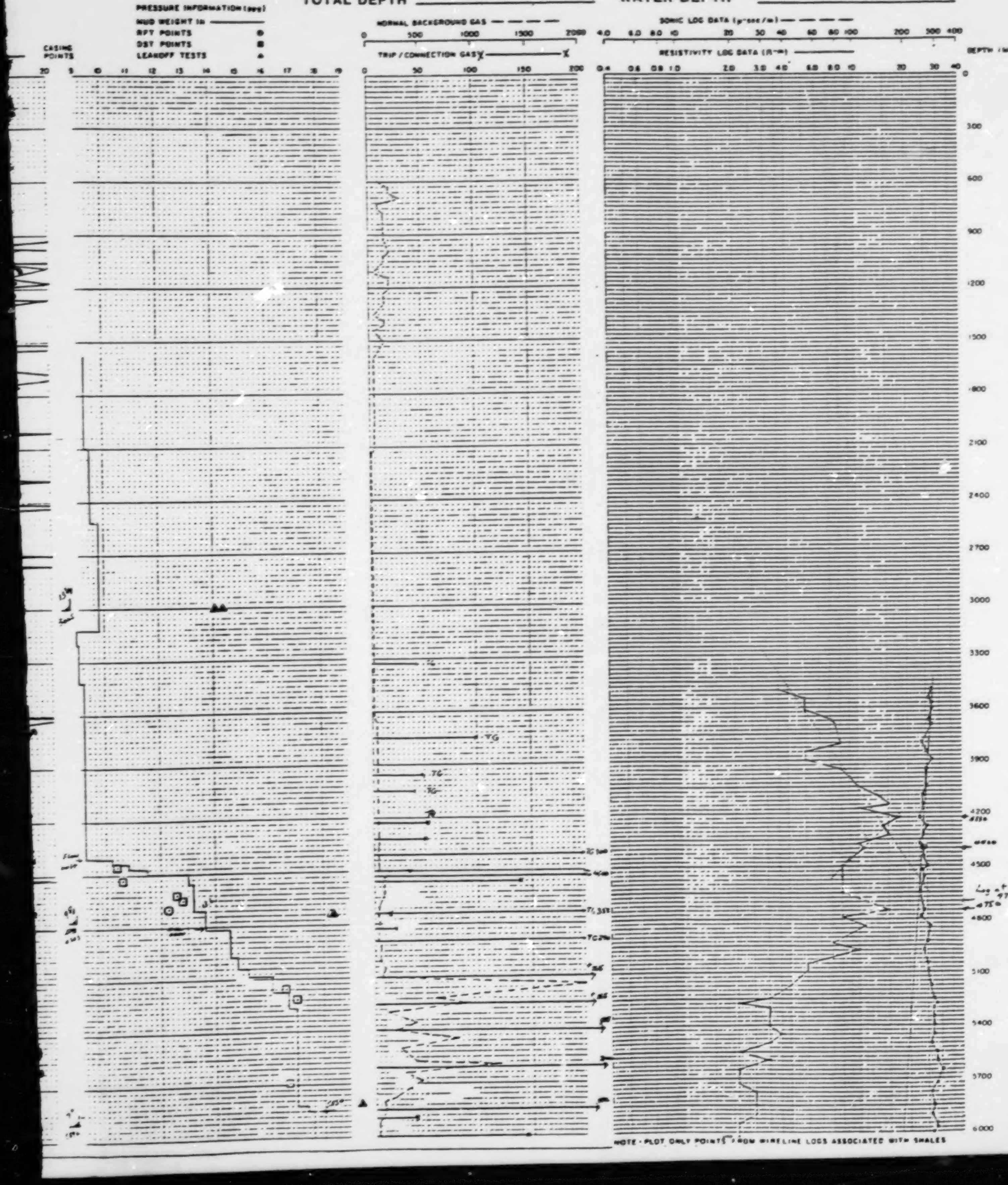
SCOTIAN SHELF GEOPRESSURE EVALUATION
PROJECT No. 059-2



S Shown

G

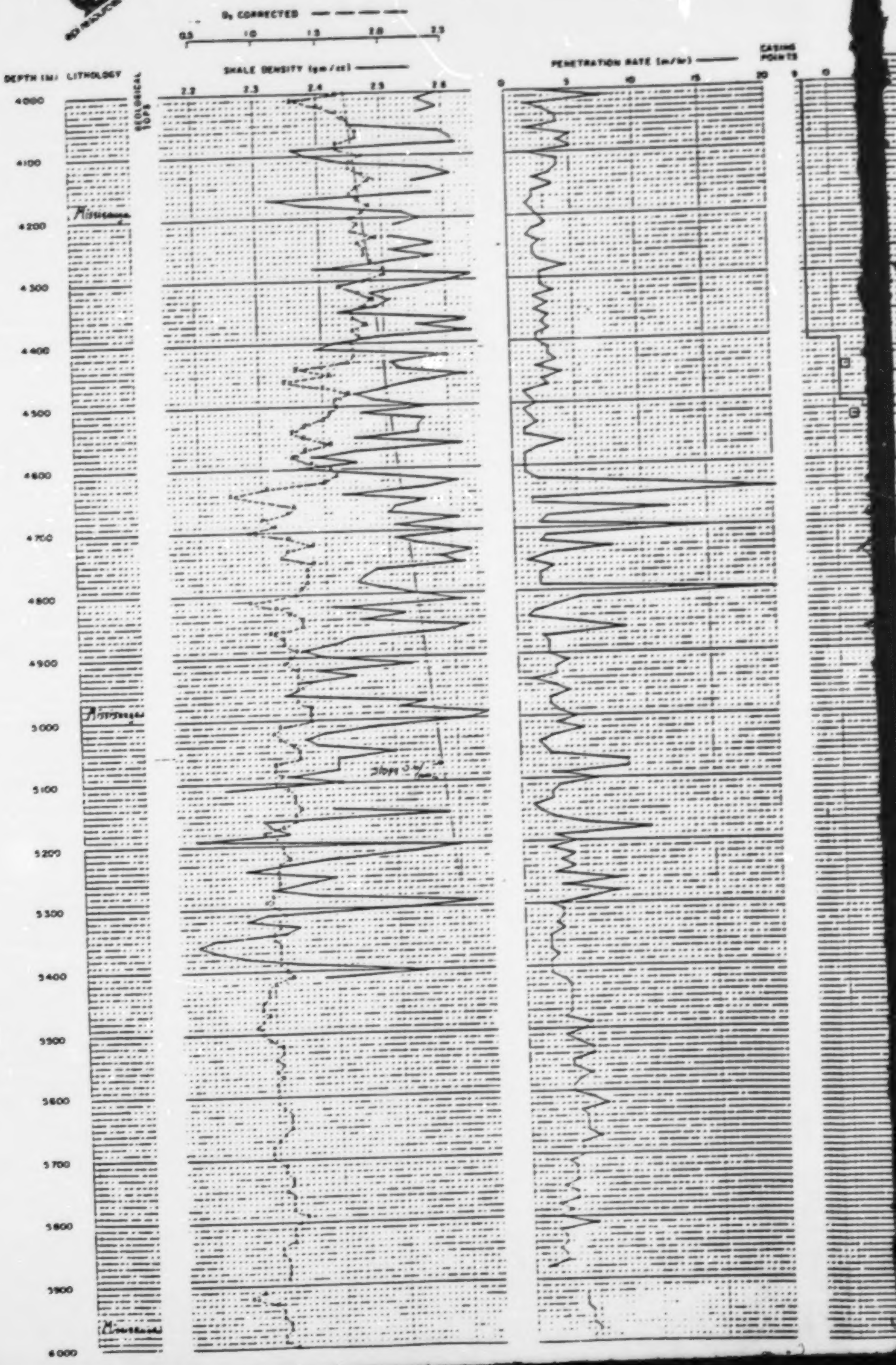
WELL NAME #5.
RIG NAME 96.
OPERATOR
LOCATION N W
SPUD DATE
COMPLETION DATE
TOTAL DEPTH
WATER DEPTH



NOTE: PLOT ONLY POINTS FROM WIRELINE LOGS ASSOCIATED WITH SHALES

PRESSURE EVALUATION LOG

SCOTIAN SHELF GEOPRESSURE EVALUATION
PROJECT No. 059-2



WELL NAME (#5 Expanded

RIG NAME ____________ 97.

OPERATOR ____________

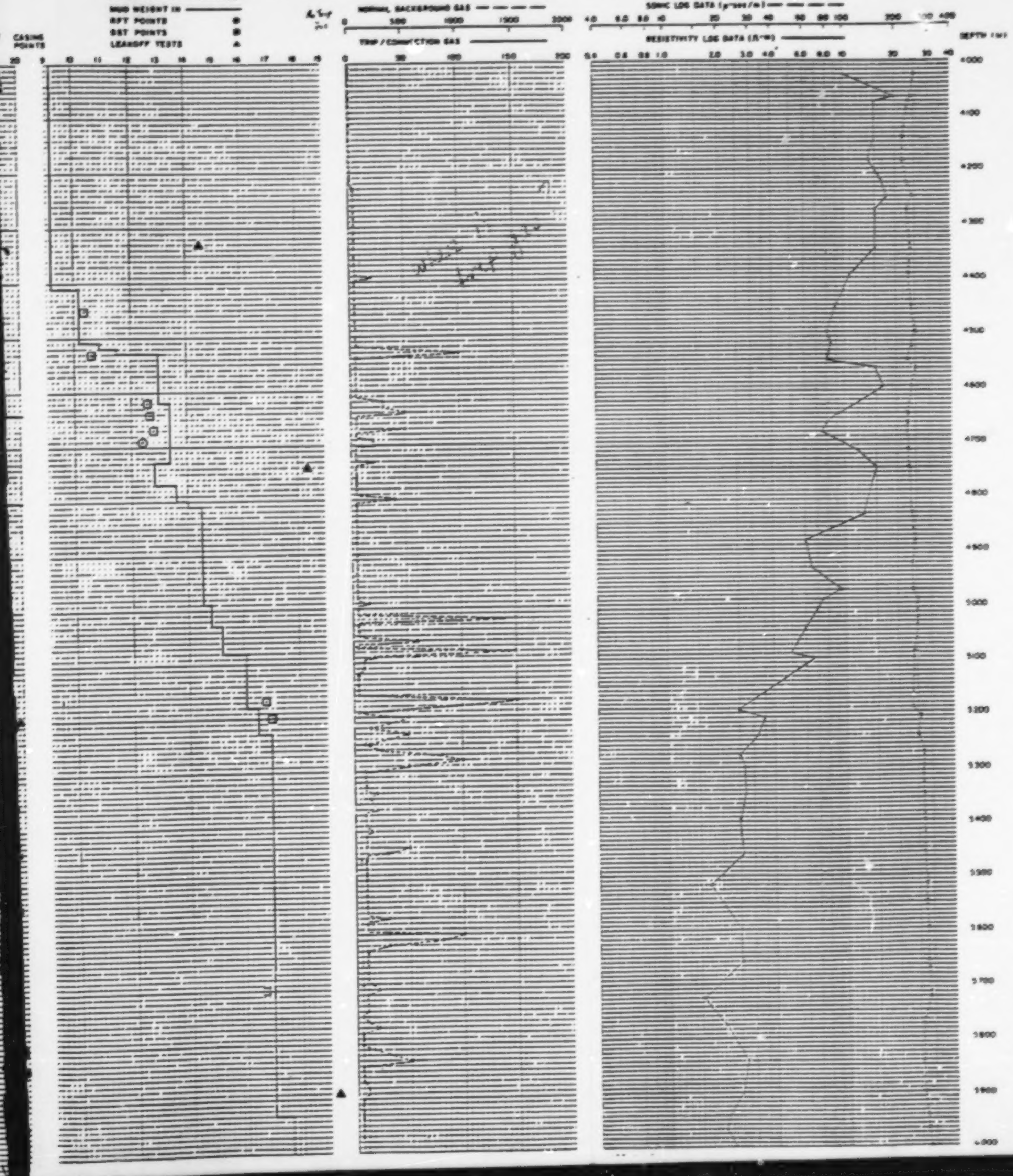
LOCATION ____________ N ____________ W

SPUD DATE ____________

COMPLETION DATE ____________

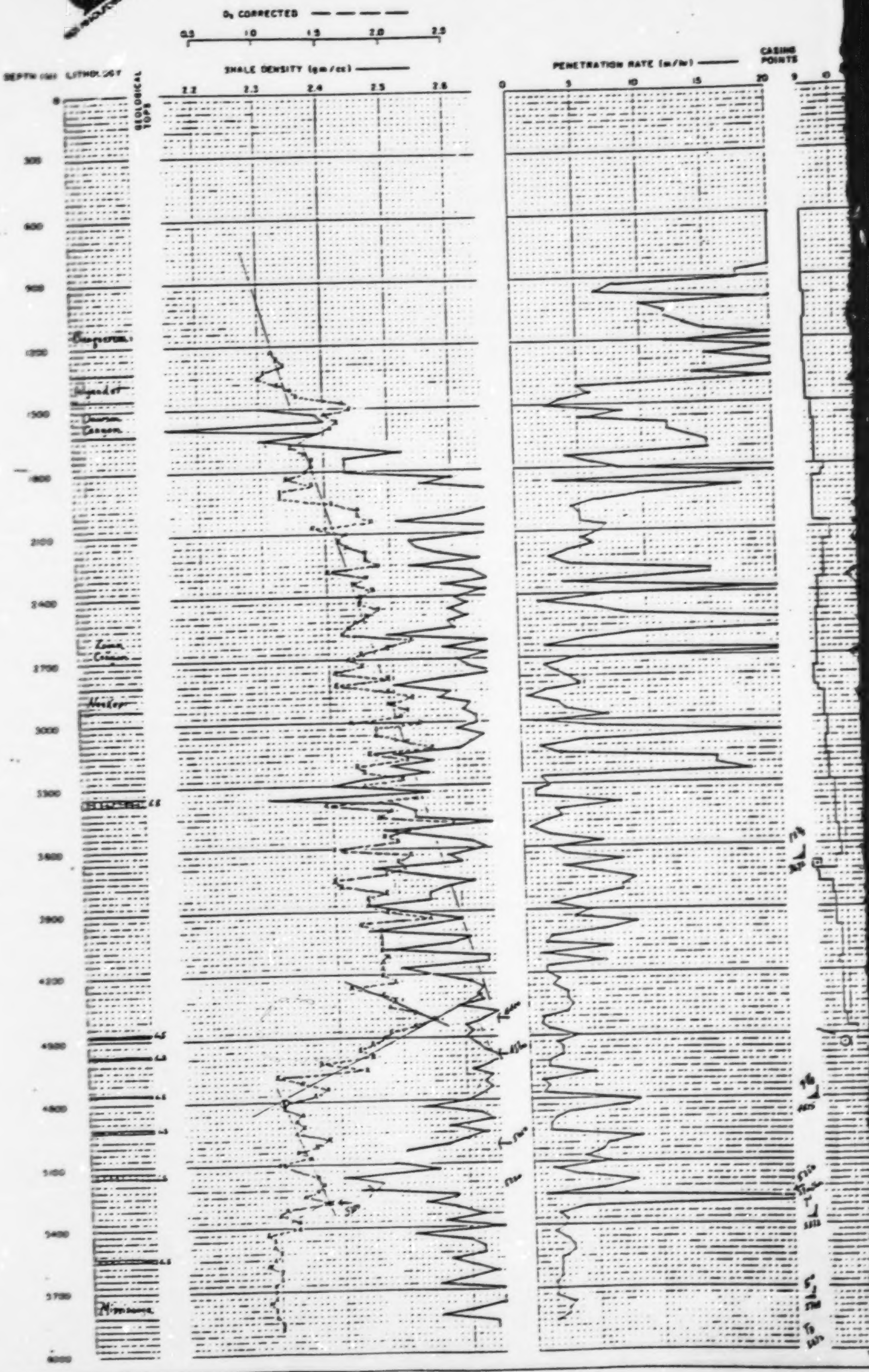
TOTAL DEPTH ____________

WATER DEPTH ____________

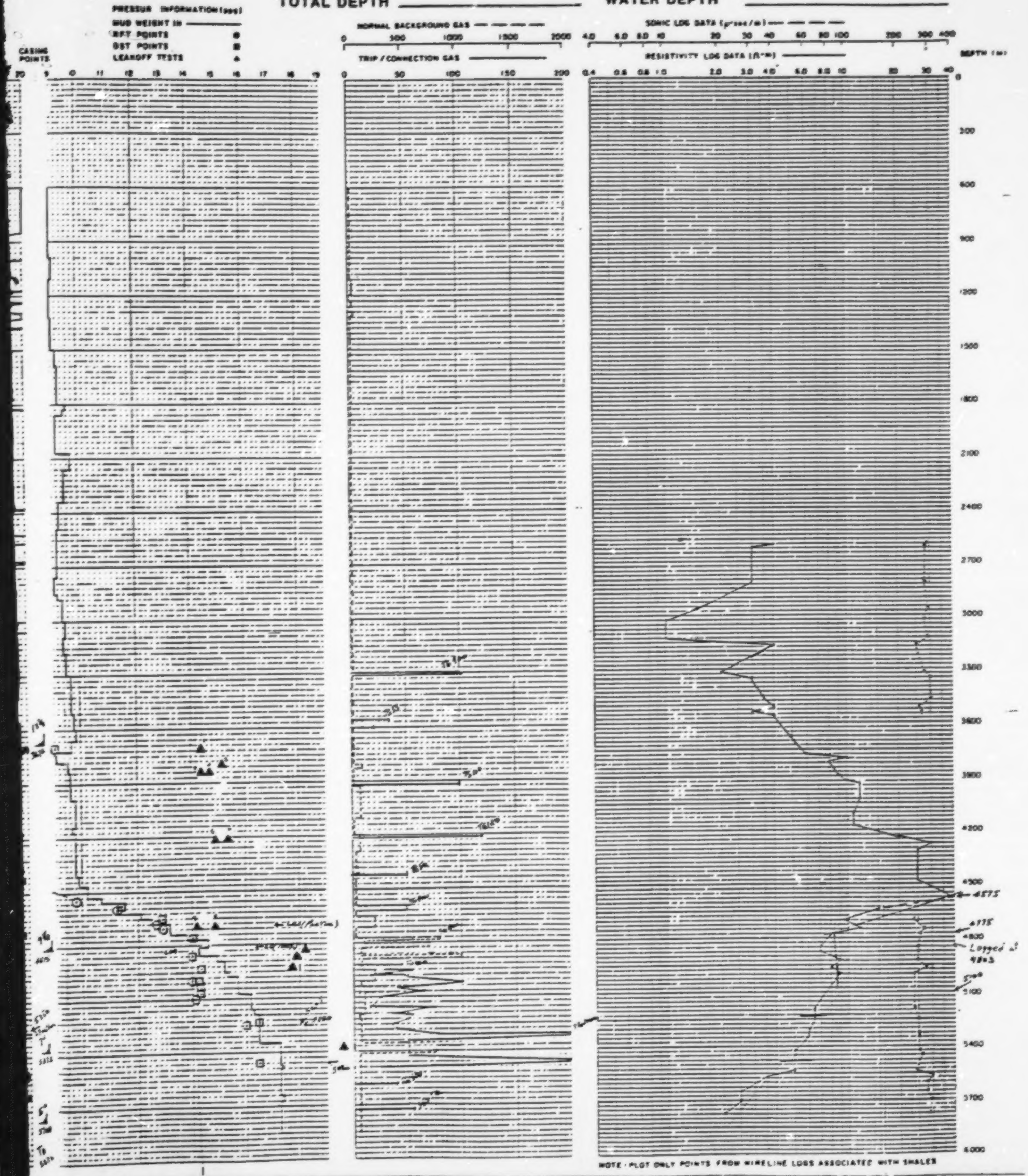


PRESSURE EVALUATION LOG

SCOTIAN SHELF GEOPRESSURE EVALUATION
PROJECT No. 059-2



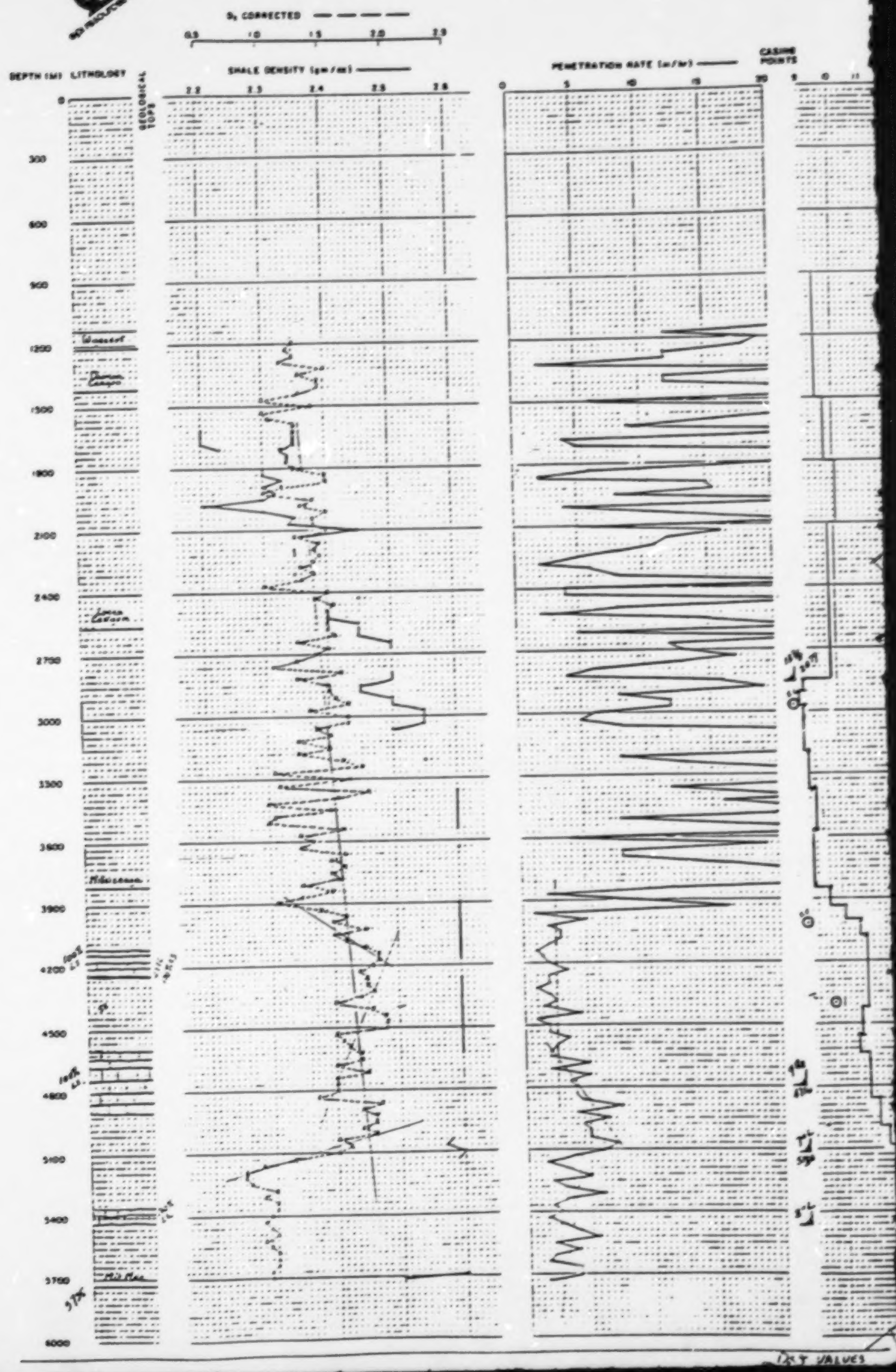
WELL NAME (#6.)
RIG NAME
OPERATOR
LOCATION N W
SPUD DATE
COMPLETION DATE
TOTAL DEPTH
WATER DEPTH



NOTE: PLOT ONLY POINTS FROM WIRELINE LOGS ASSOCIATED WITH SHALES

PRESSURE EVALUATION LOG

SCOTIAN SHELF GEOPRESSURE EVALUATION
PROJECT No. 059-2



WELL NAME (7)

RIG NAME 99.

OPERATOR

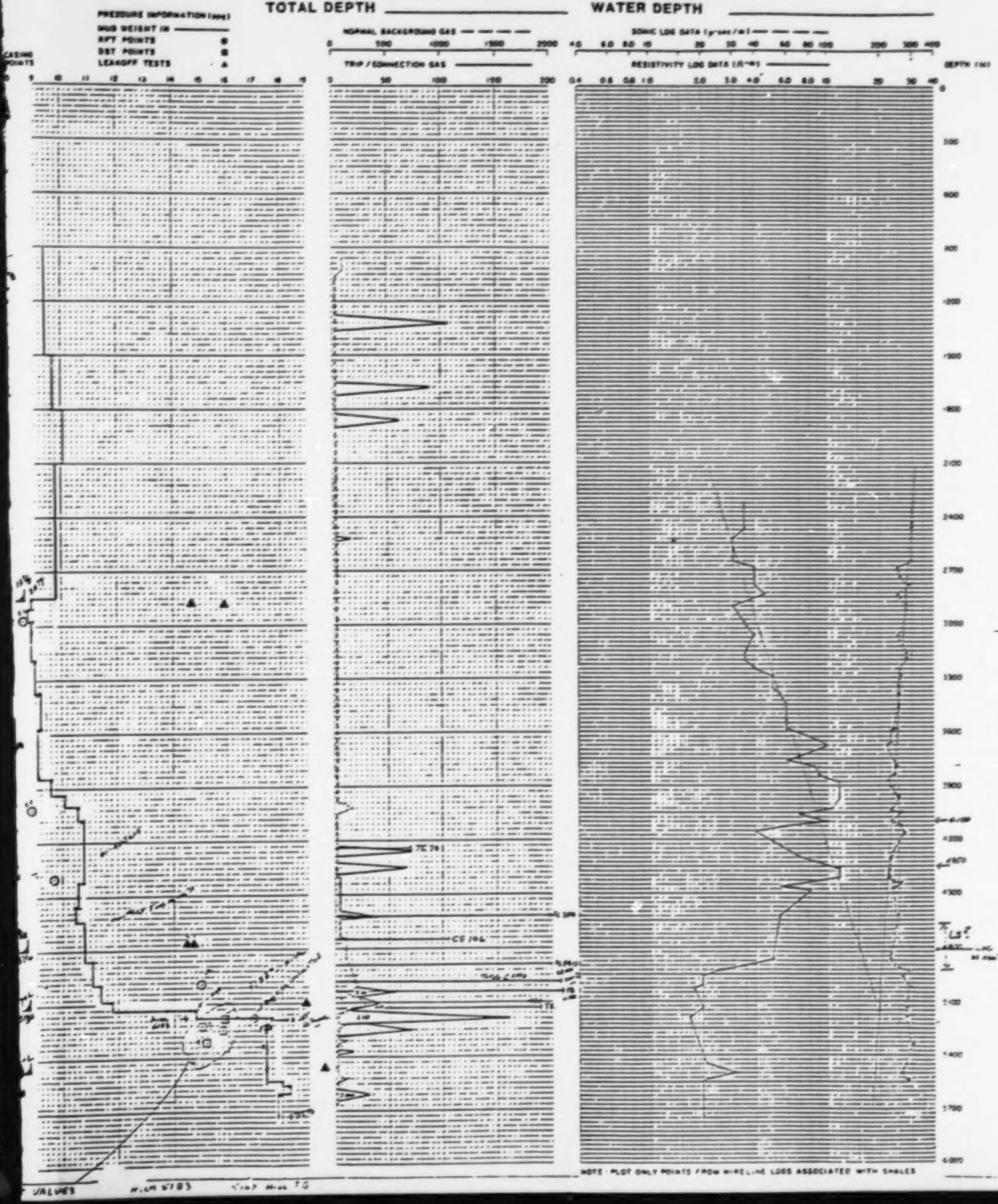
LOCATION N W

SPUD DATE

COMPLETION DATE

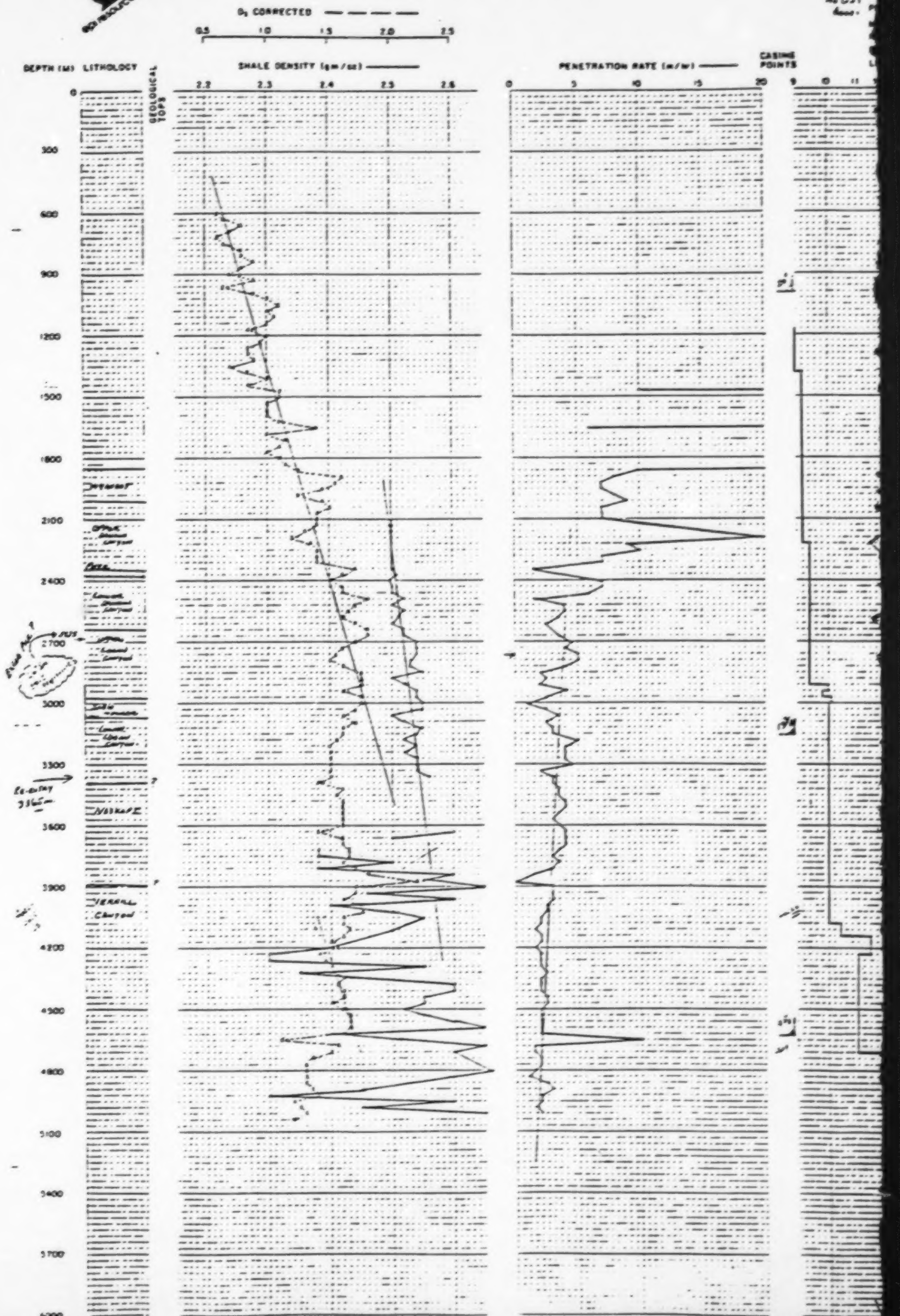
TOTAL DEPTH

WATER DEPTH



PRESSURE EVALUATION LOG

SCOTIAN SHELF GEOPRESSURE EVALUATION
PROJECT No. 059-2



WELL NAME (#8.)

OPERATOR

SPUD DATE

TOTAL DEPTH

RIG NAME

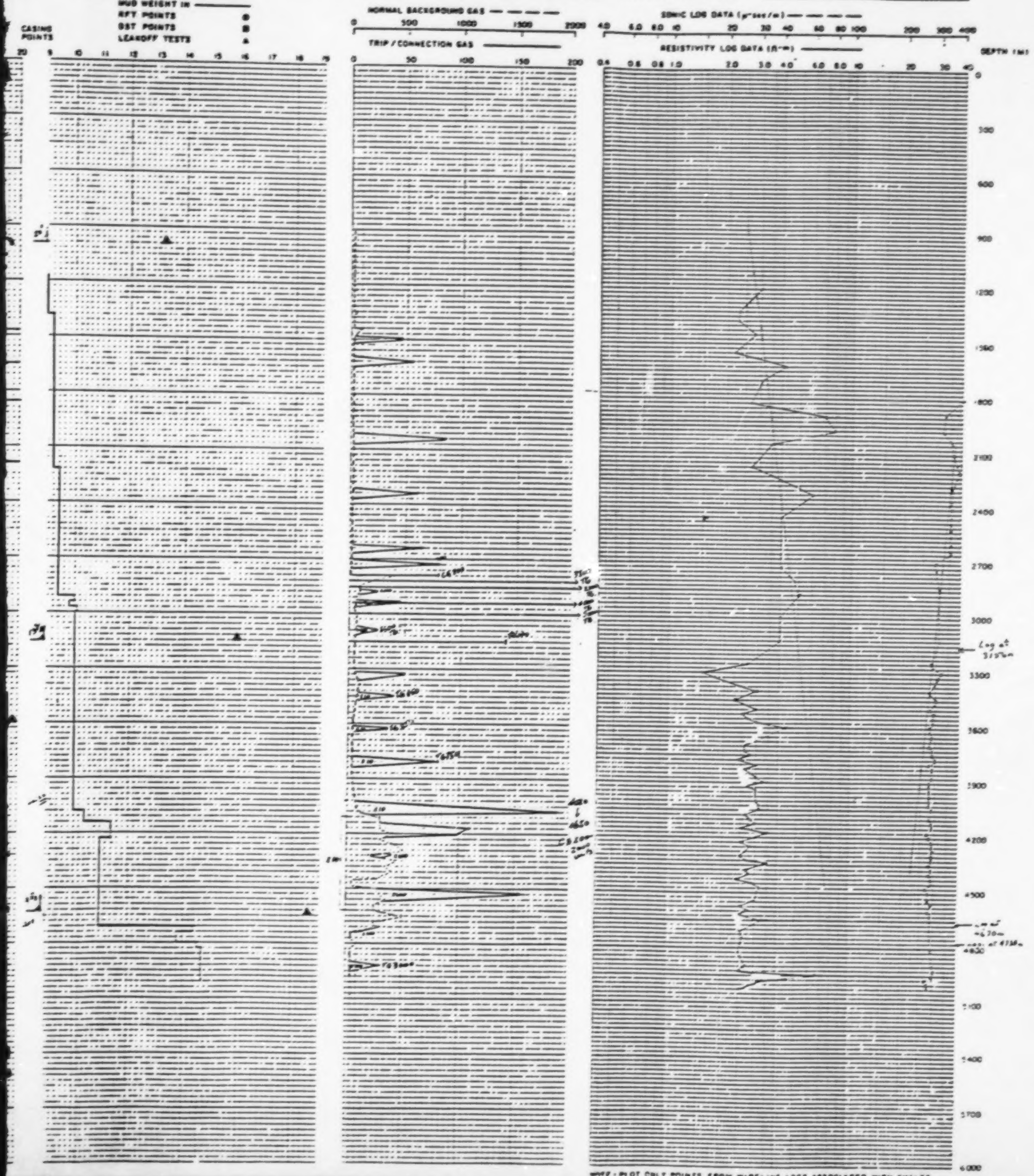
LOCATION N W

COMPLETION DATE

WATER DEPTH

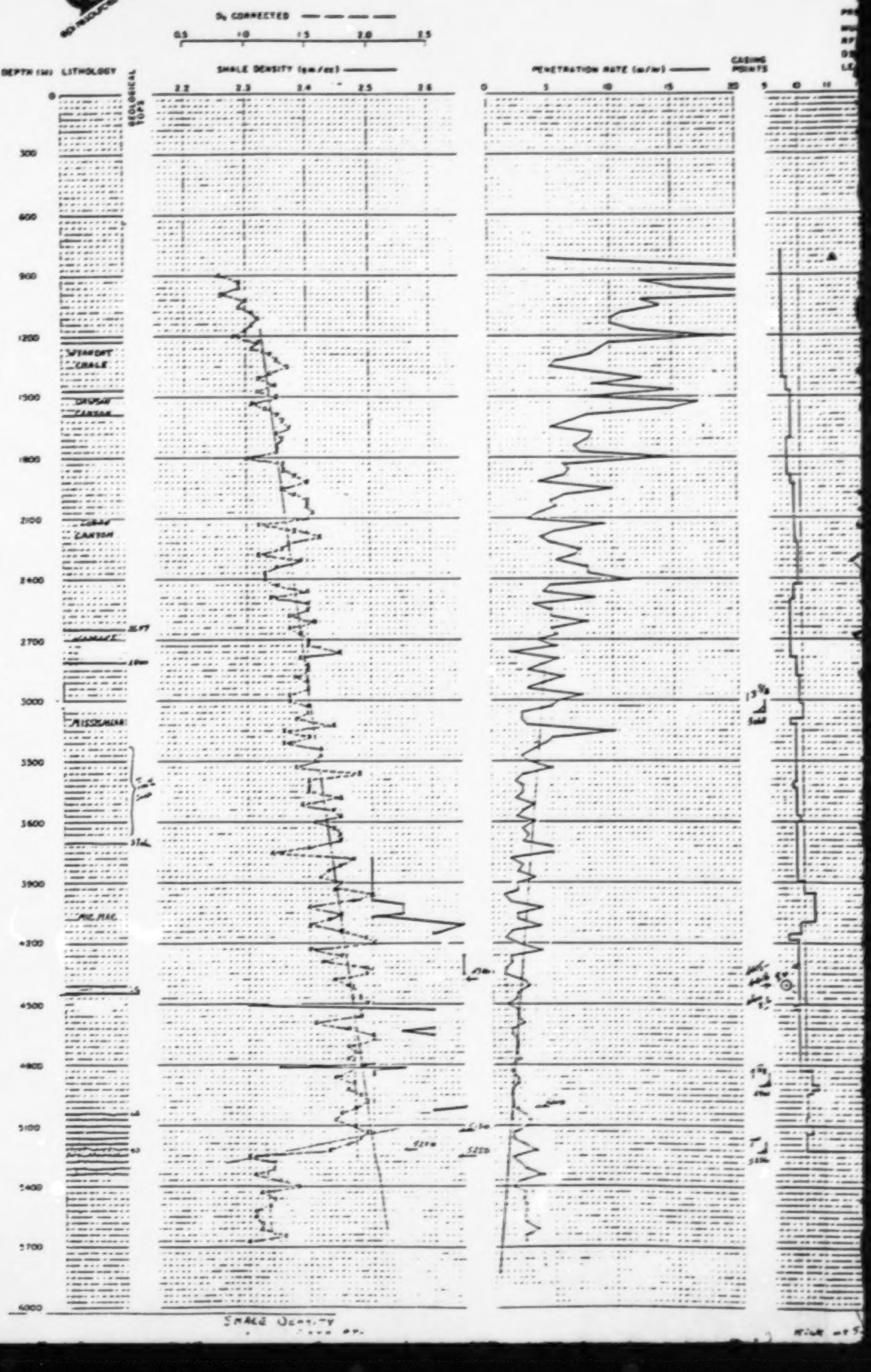
no RFT data available from Schlumberger.

No DST done.



PRESSURE EVALUATION LOG

SCOTIAN SHELF GEOPRESSURE EVALUATION
PROJECT No. 059-2



WELL NAME (#9.)

OPERATOR

SPUD DATE

TOTAL DEPTH

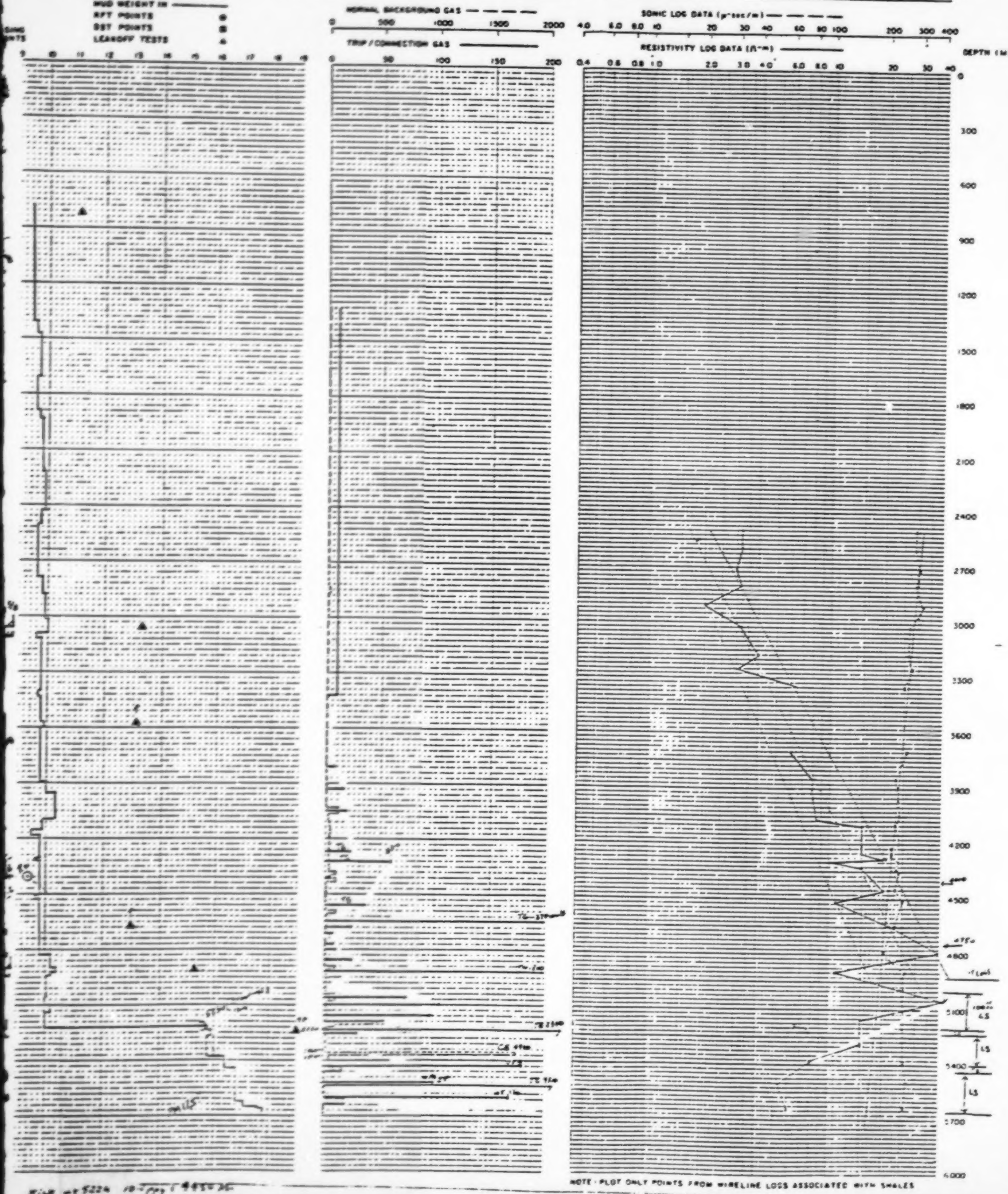
RIG NAME

LOCATION N W

COMPLETION DATE

WATER DEPTH

no DST done

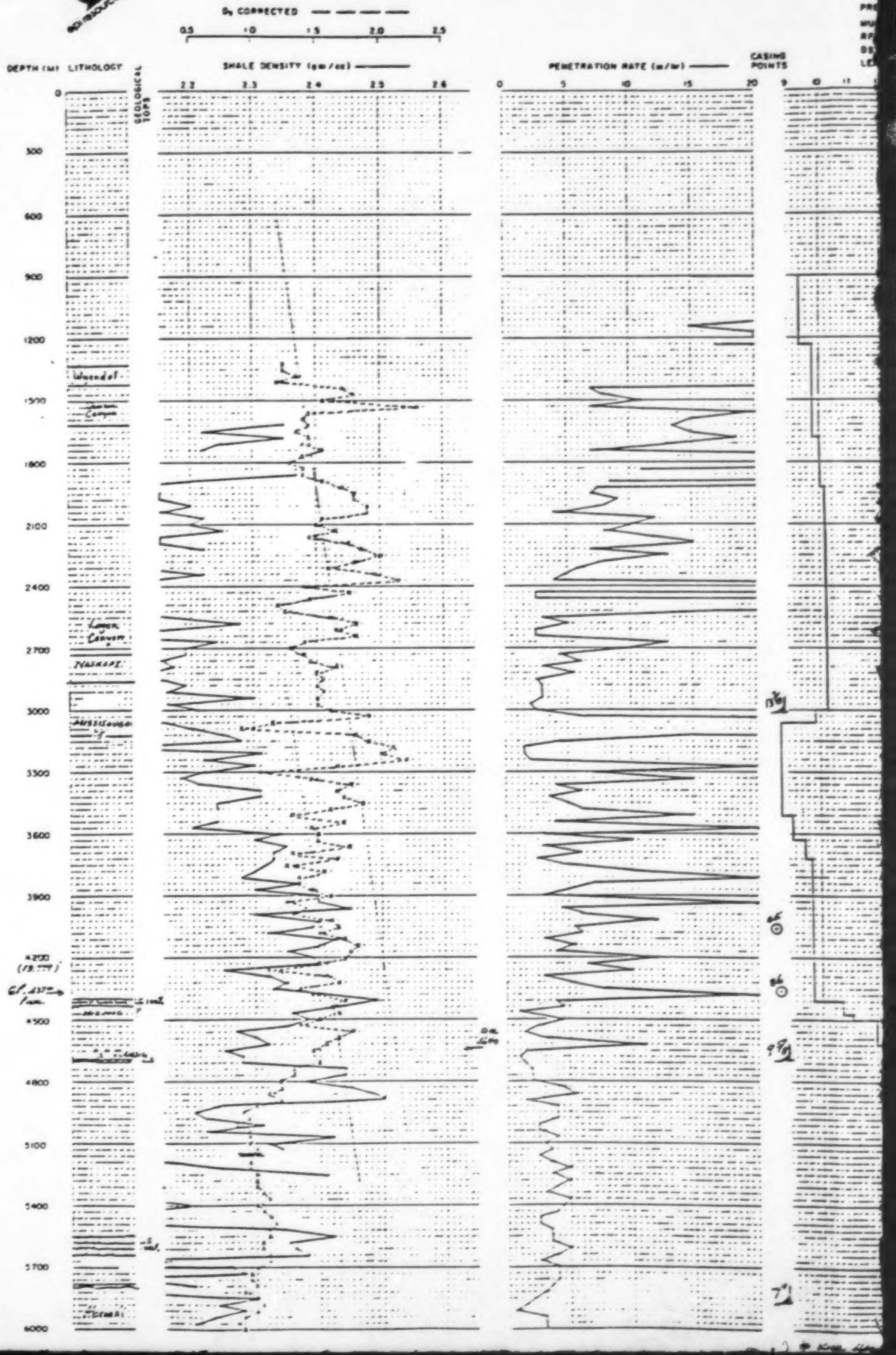


NOTE: PLOT ONLY POINTS FROM WIRELINE LOGS ASSOCIATED WITH SHALES

Kick at 5224 10.7 ppg

PRESSURE EVALUATION LOG

SCOTIAN SHELF GEOPRESSURE EVALUATION
PROJECT No. 059-2



WELL NAME (#10.)

OPERATOR

SPUD DATE

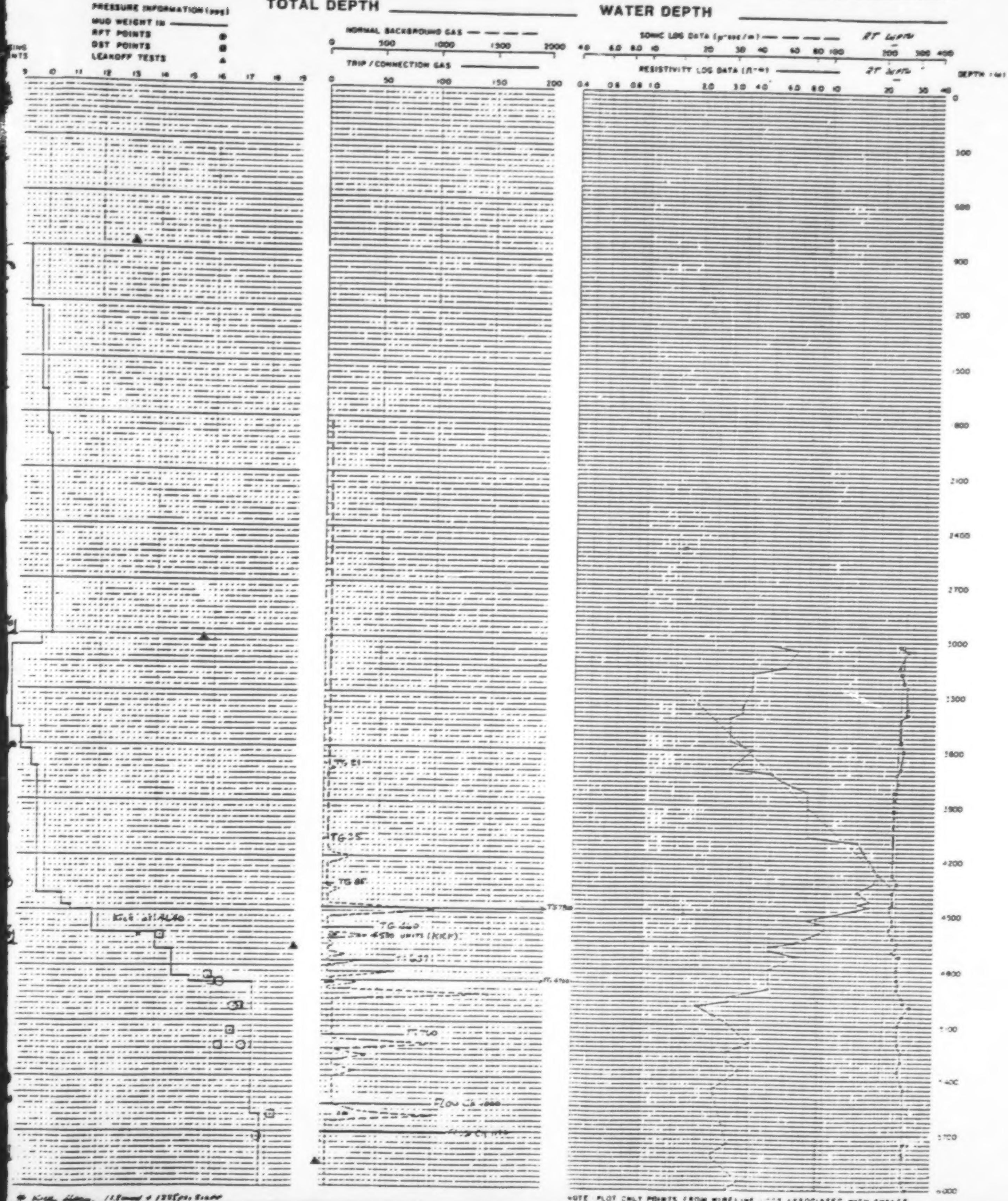
TOTAL DEPTH

RIG NAME

LOCATION N W

COMPLETION DATE

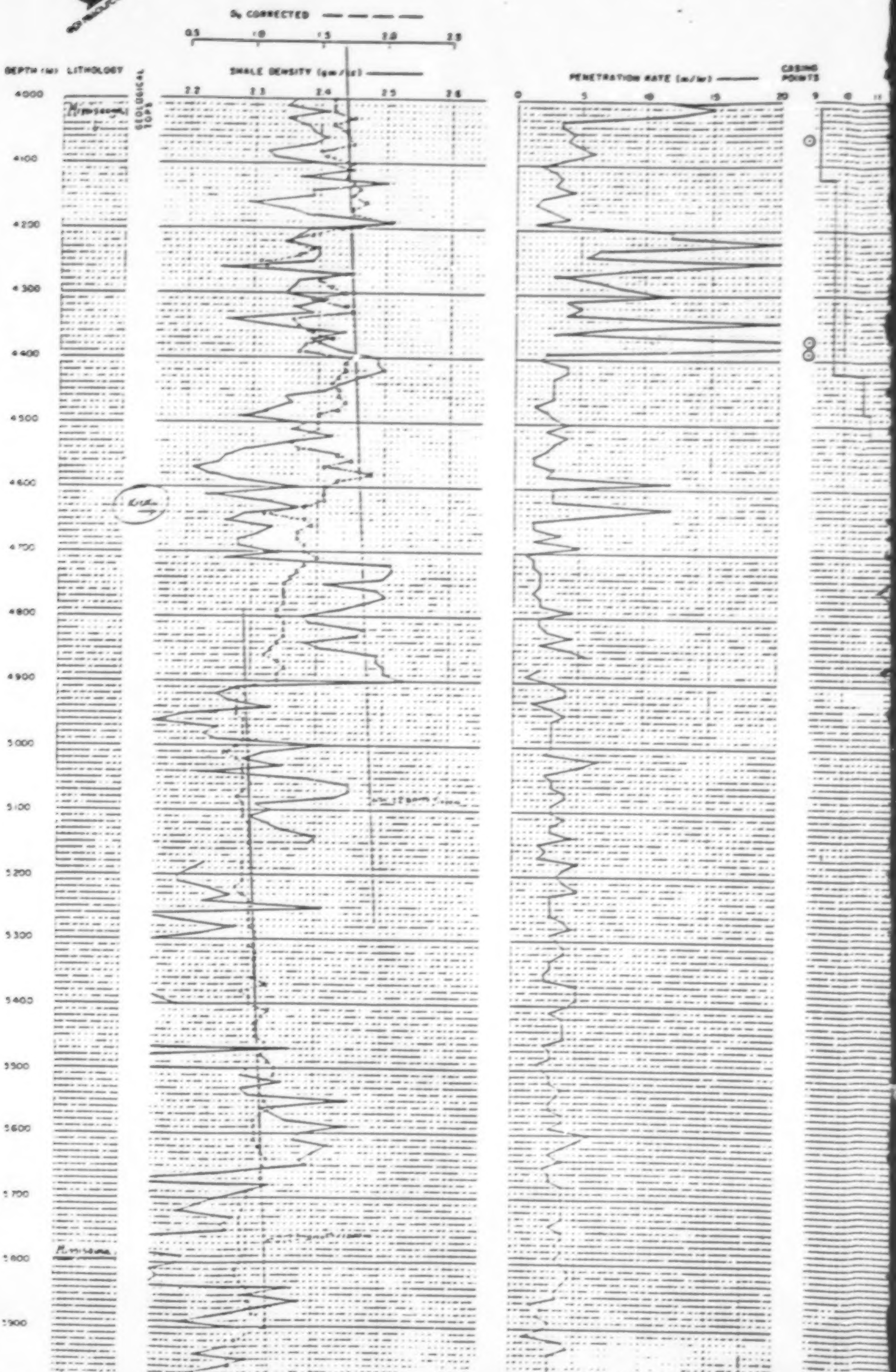
WATER DEPTH



NOTE: PLOT ONLY POINTS FROM WIRELINE LOGS ASSOCIATED WITH SHALES

PRESSURE EVALUATION LOG

SCOTIAN SHELF GEOPRESSURE EVALUATION
PROJECT No. 059-2



WELL NAME #10. EXPANDED

RIG NAME

OPERATOR

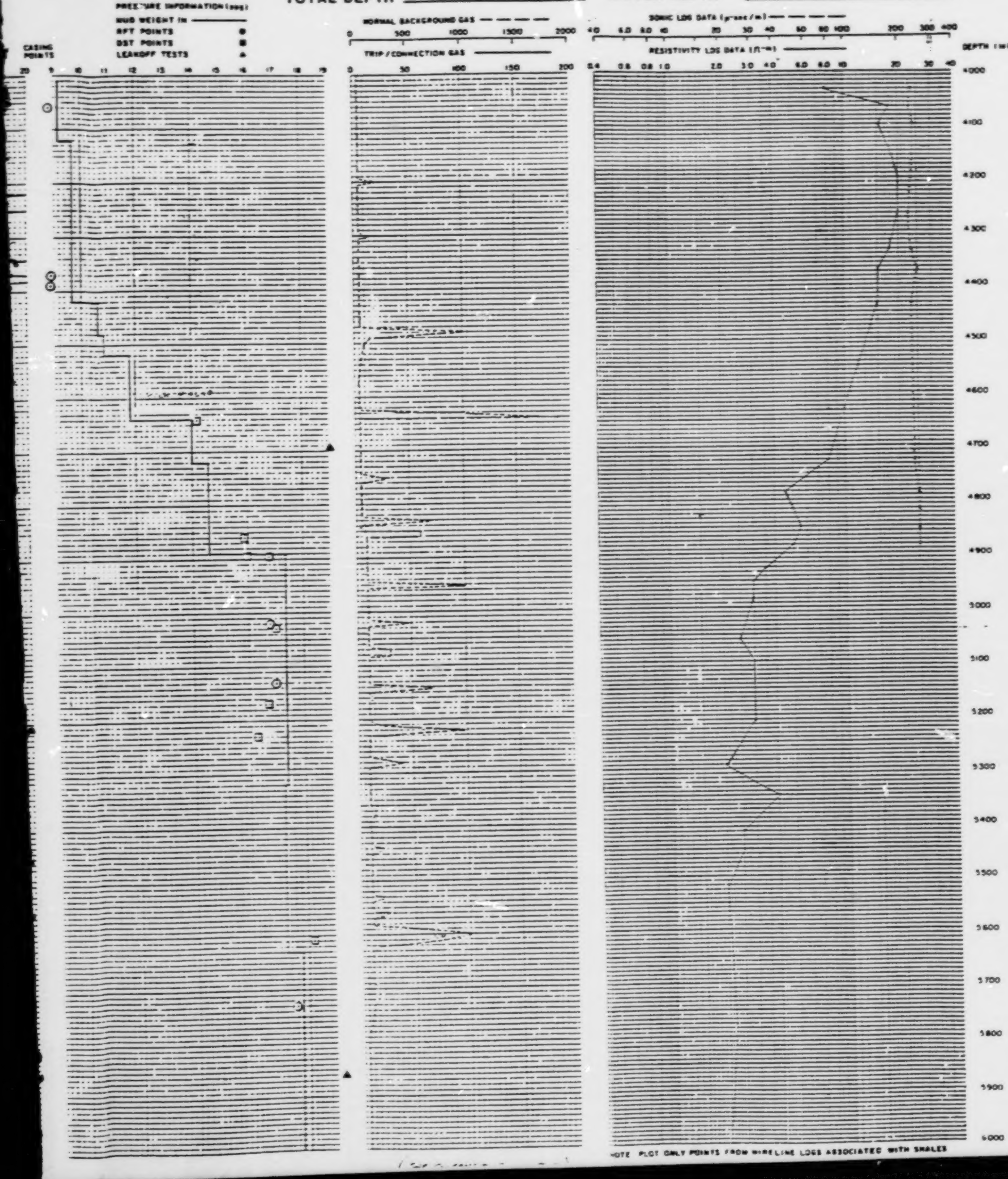
LOCATION N W

SPUD DATE

COMPLETION DATE

TOTAL DEPTH

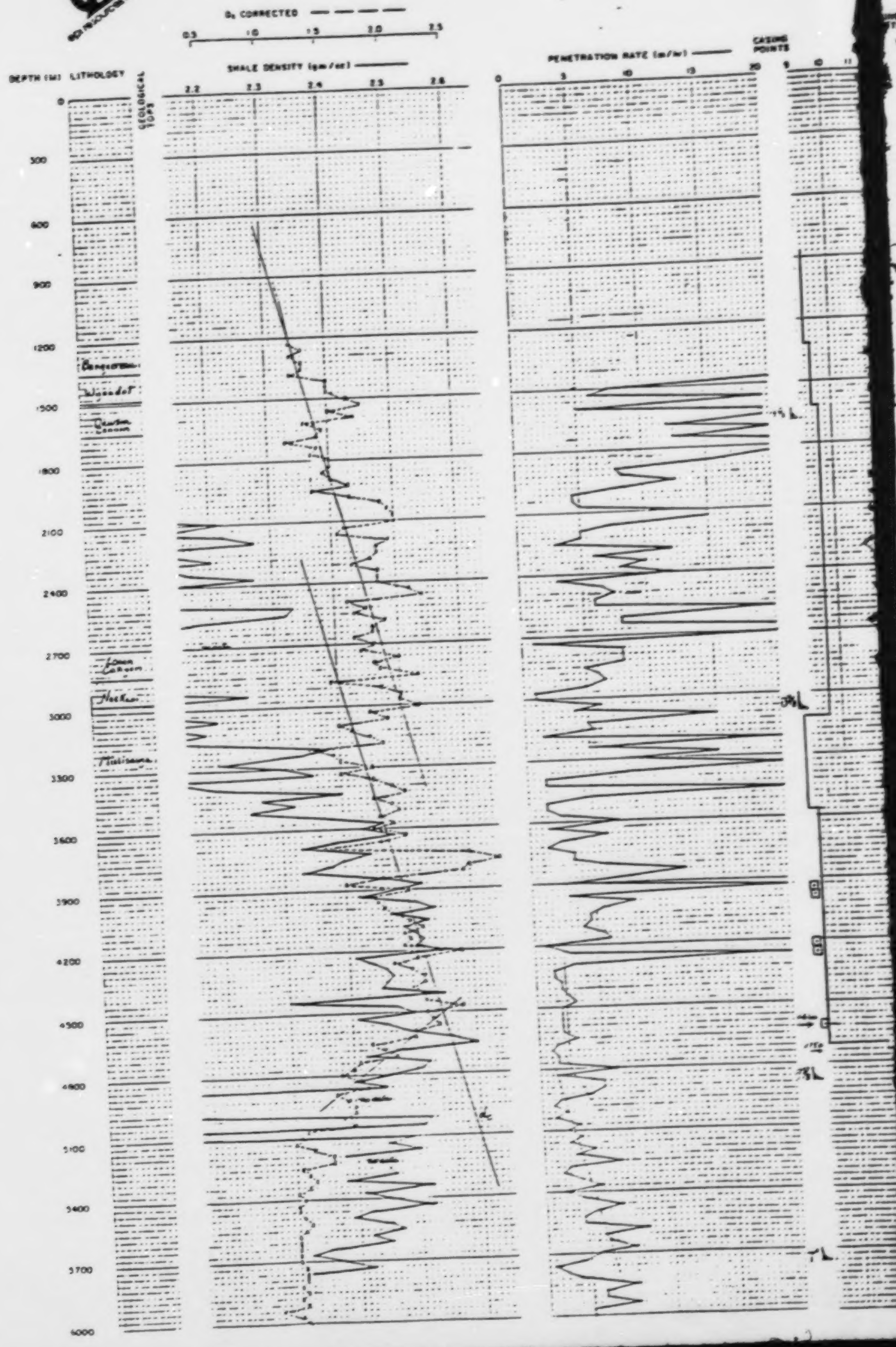
WATER DEPTH



NOTE PLOT ONLY POINTS FROM WIRELINE LOGS ASSOCIATED WITH SHALES

PRESSURE EVALUATION LOG

SCOTIAN SHELF GEOPRESSURE EVALUATION
PROJECT No. 059-2



WELL NAME (#11.)

OPERATOR

SPUD DATE

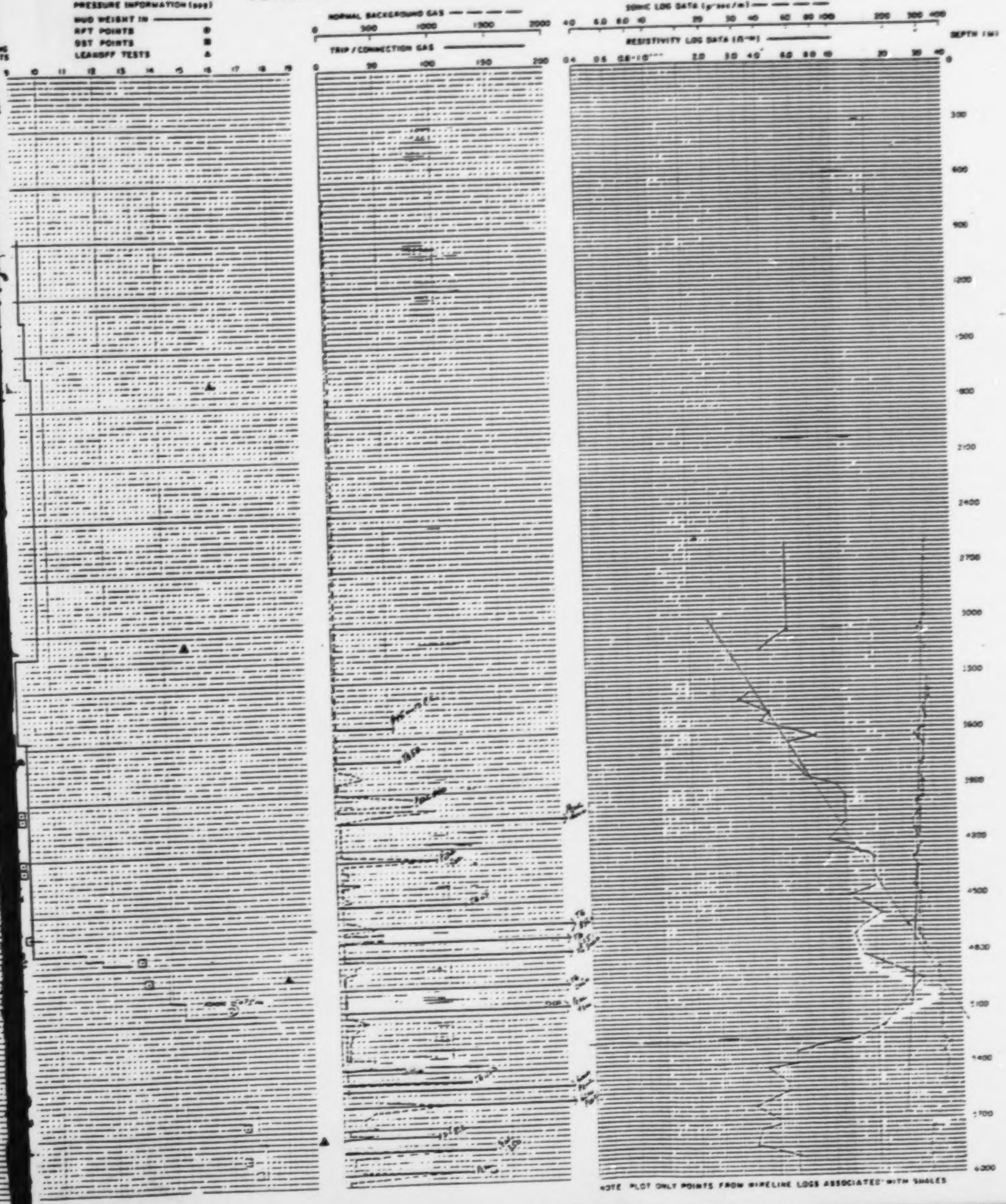
TOTAL DEPTH

RIG NAME

LOCATION N W 104.

COMPLETION DATE

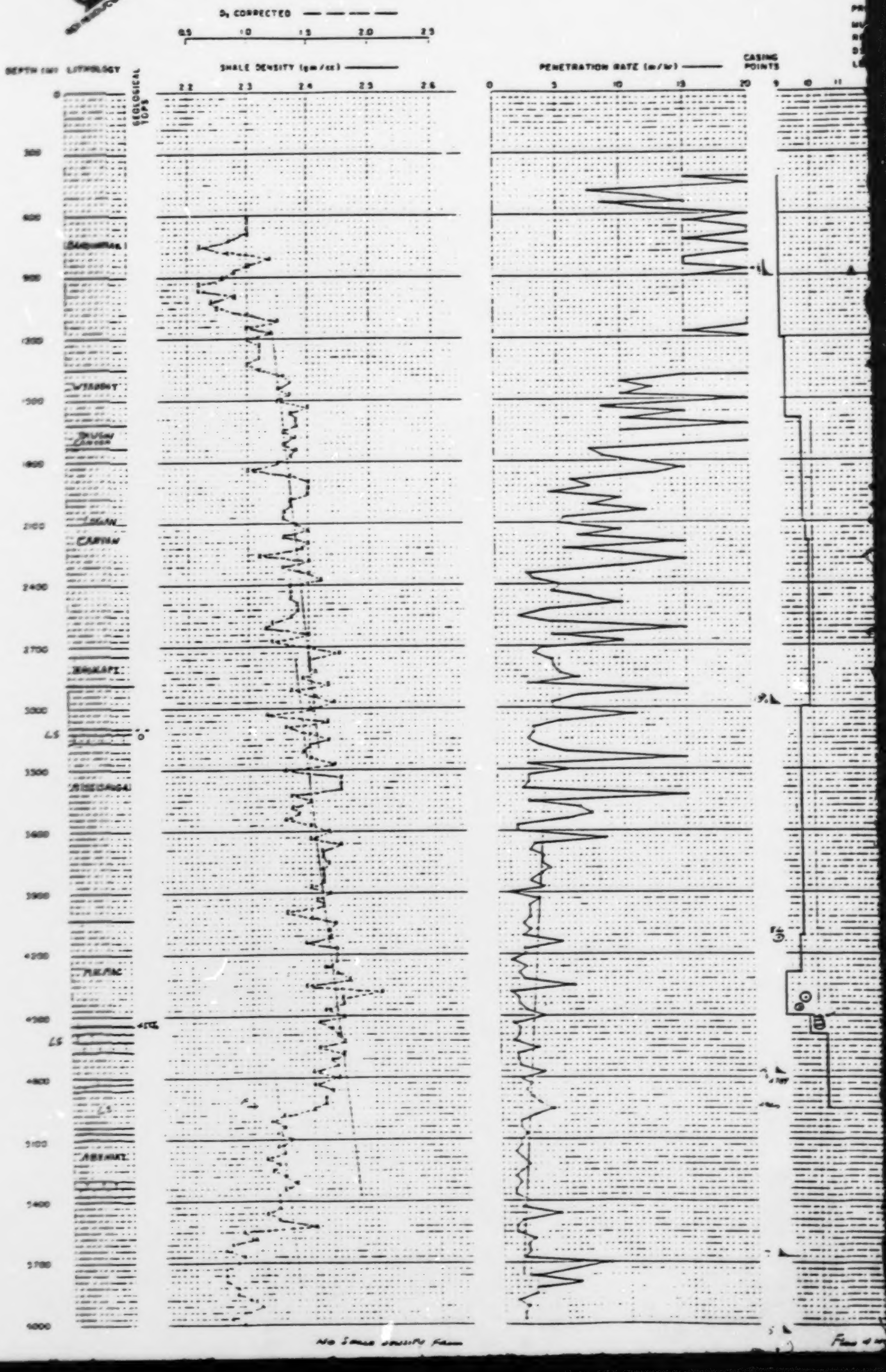
WATER DEPTH



NOTE: PLOT ONLY POINTS FROM WIRELINE LOGS ASSOCIATED WITH SHALES

PRESSURE EVALUATION LOG

SCOTIAN SHELF GEOPRESSURE EVALUATION
PROJECT No. 059-2



WELL NAME (#12.)

OPERATOR

SPUD DATE

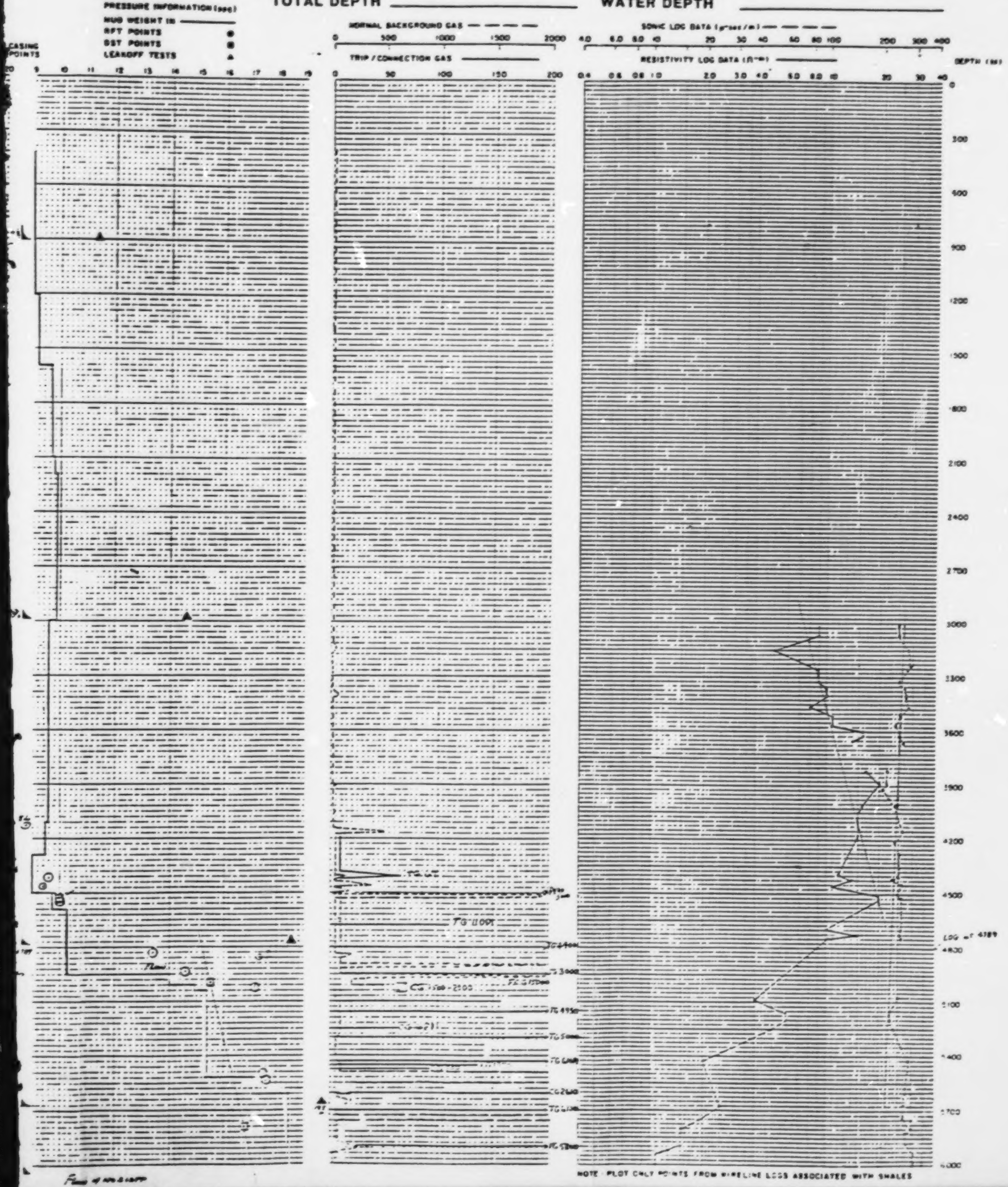
TOTAL DEPTH

RIG NAME

LOCATION N W

COMPLETION DATE

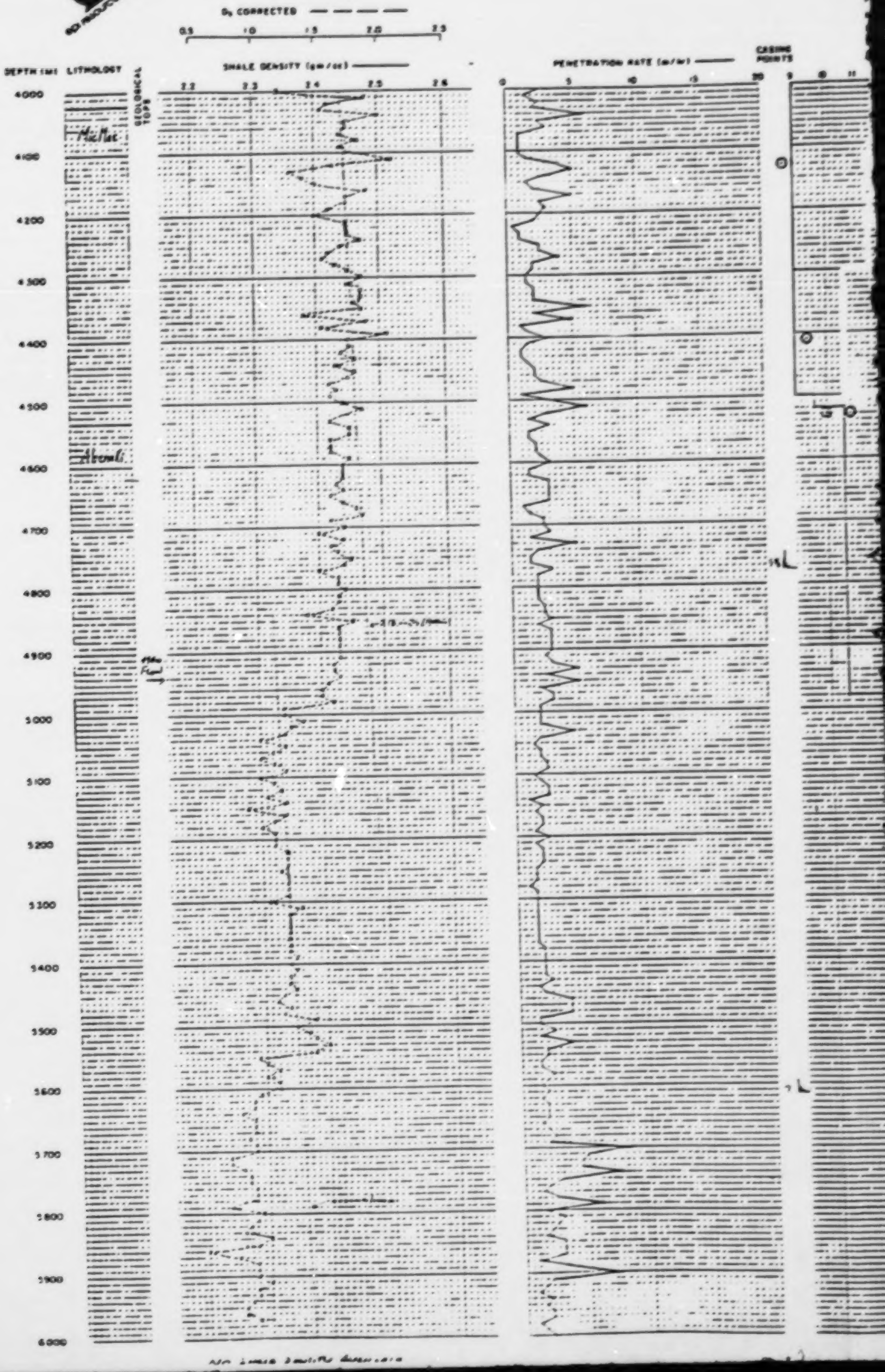
WATER DEPTH



NOTE: PLOT ONLY POINTS FROM WIRELINE LOGS ASSOCIATED WITH SHALES

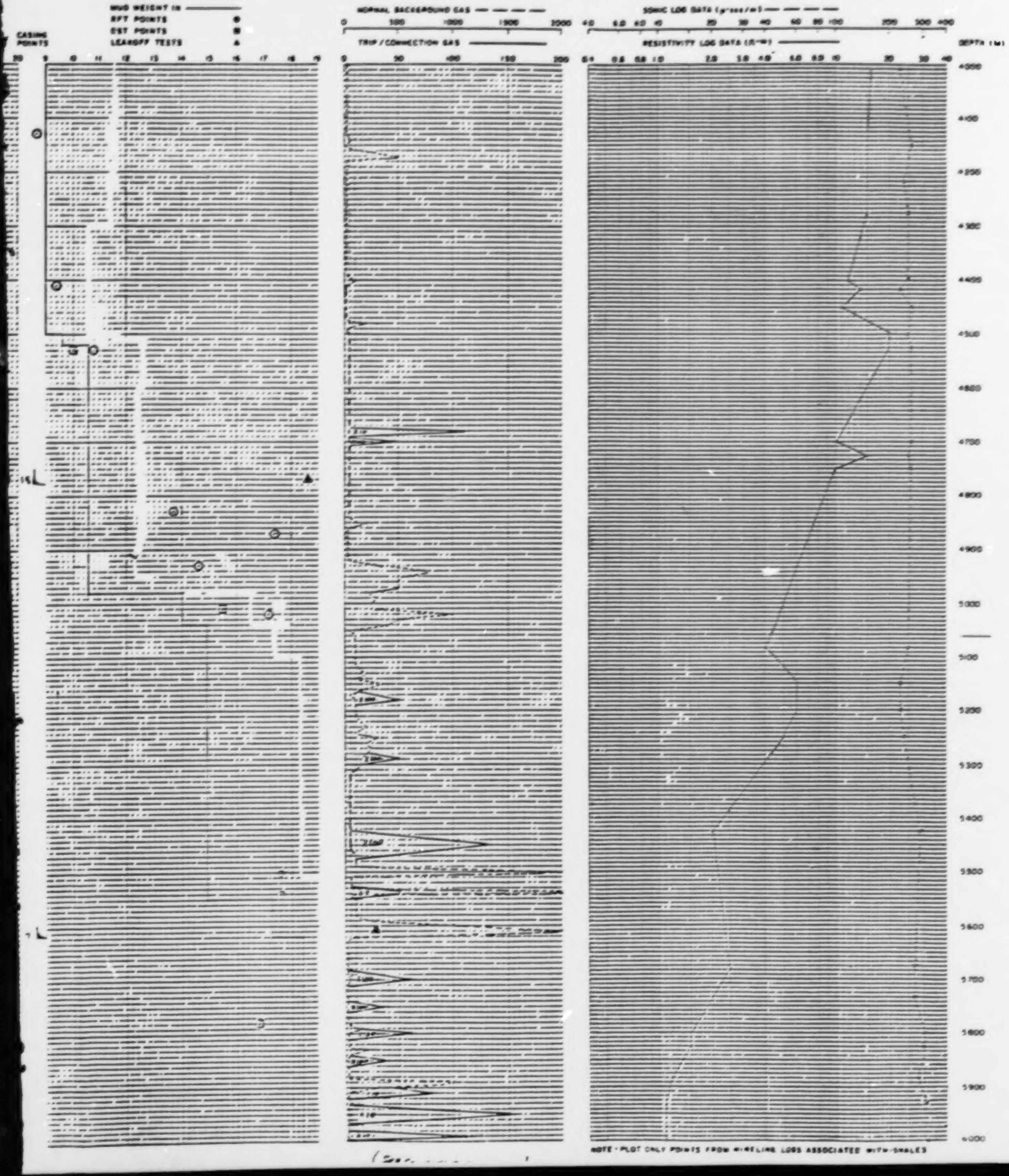
PRESSURE EVALUATION LOG

SCOTIAN SHELF GEOPRESSURE EVALUATION
PROJECT No.059-2



No Shale Density Available

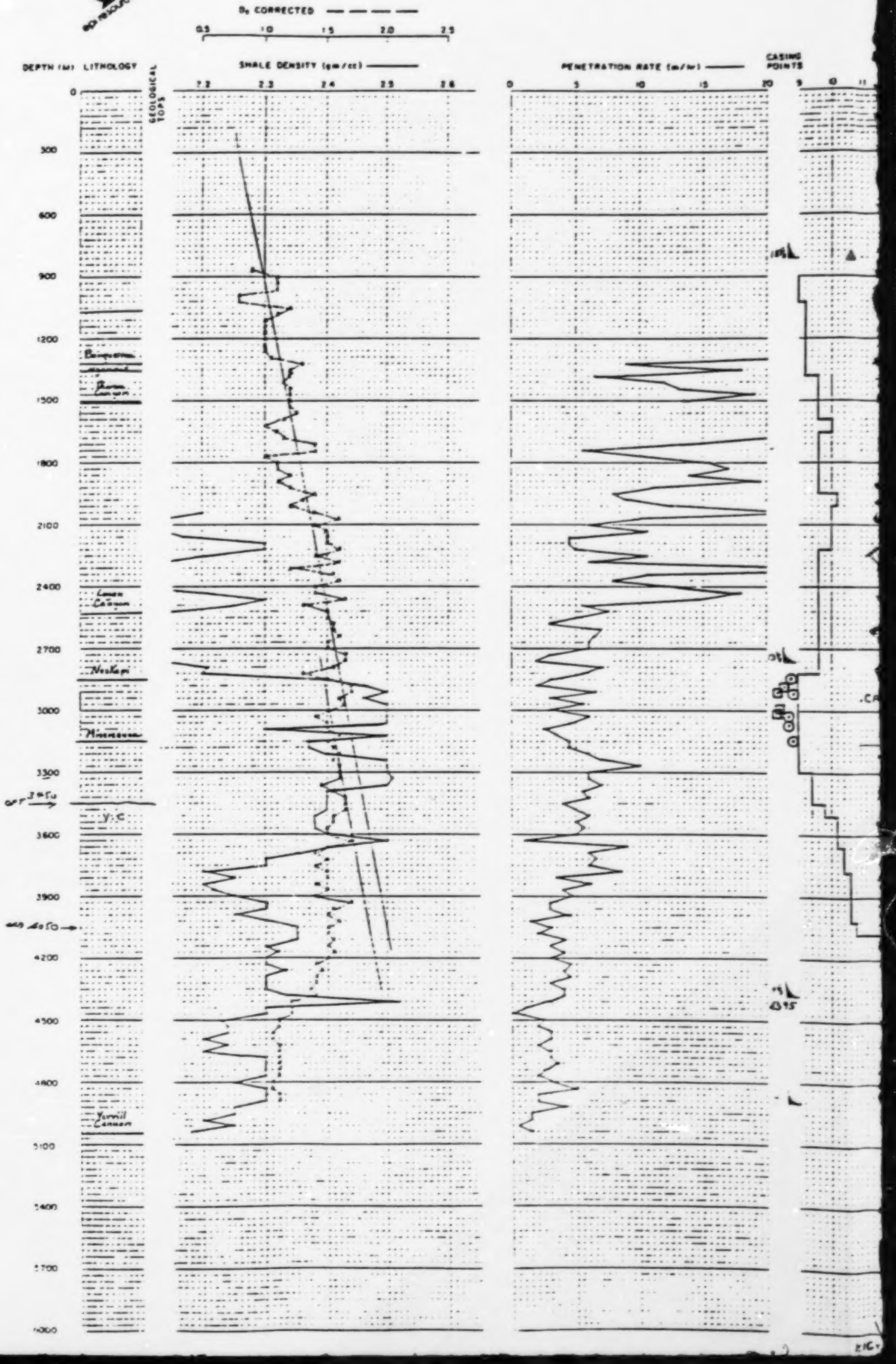
WELL NAME #12. EXPANDED
OPERATOR
SPUD DATE
TOTAL DEPTH
RIG NAME
LOCATION N W
COMPLETION DATE
WATER DEPTH



NOTE: PLOT ONLY POINTS FROM WIRELINE LOGS ASSOCIATED WITH SHALES

PRESSURE EVALUATION LOG

SCOTIAN SHELF GEOPRESSURE EVALUATION
PROJECT No. 059-2



WELL NAME (#13)

OPERATOR

SPUD DATE

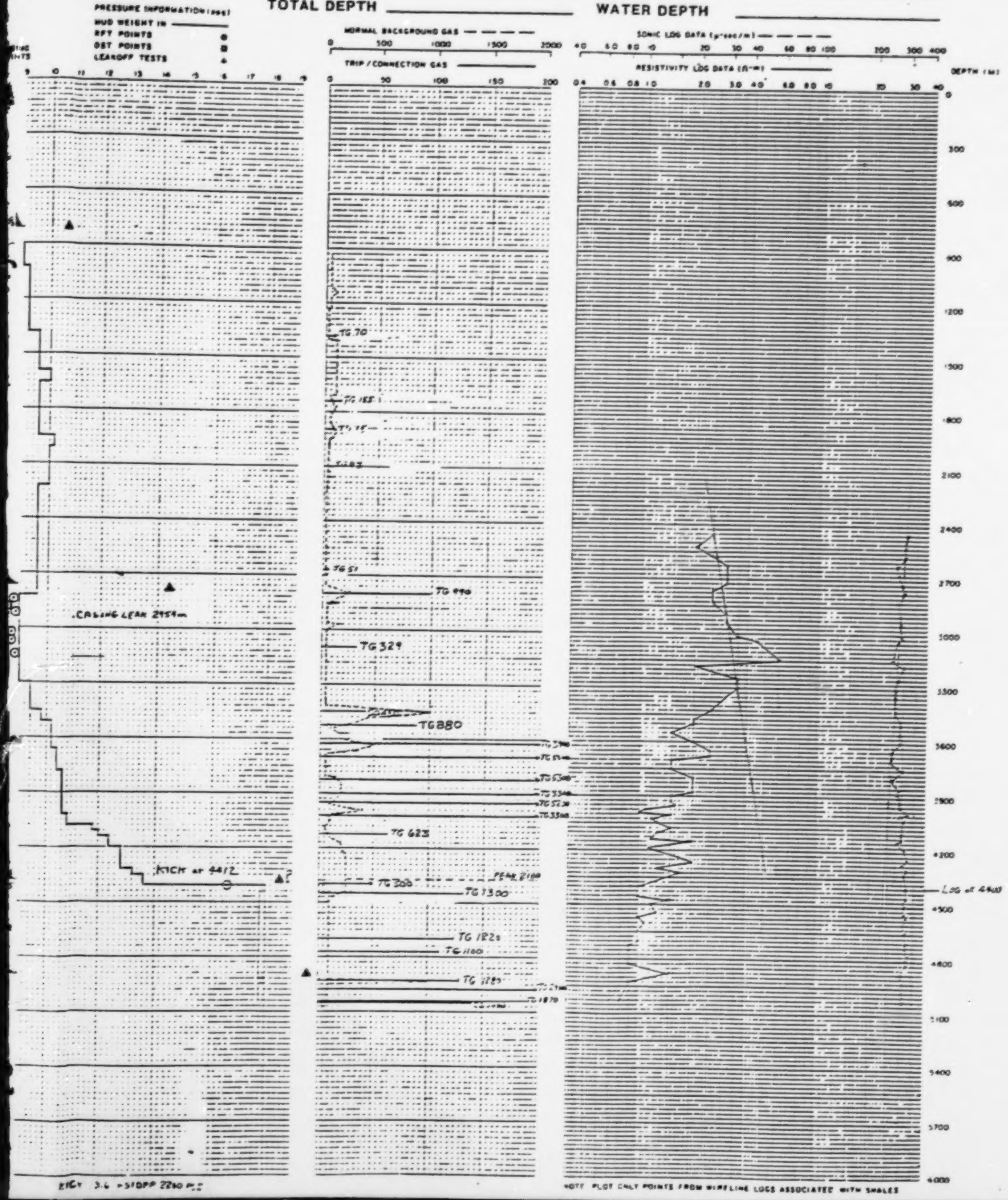
TOTAL DEPTH

RIG NAME

LOCATION N W

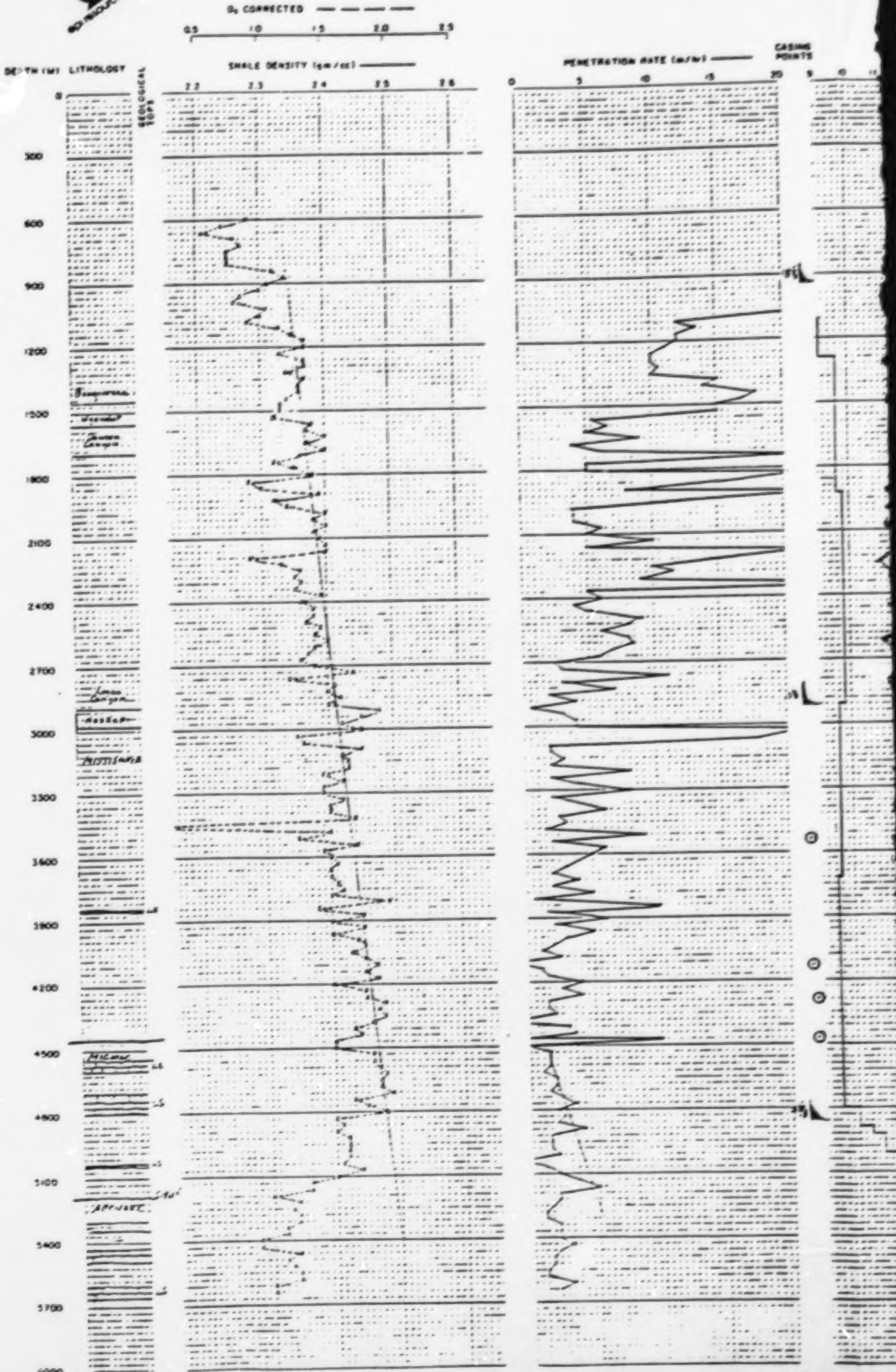
COMPLETION DATE

WATER DEPTH



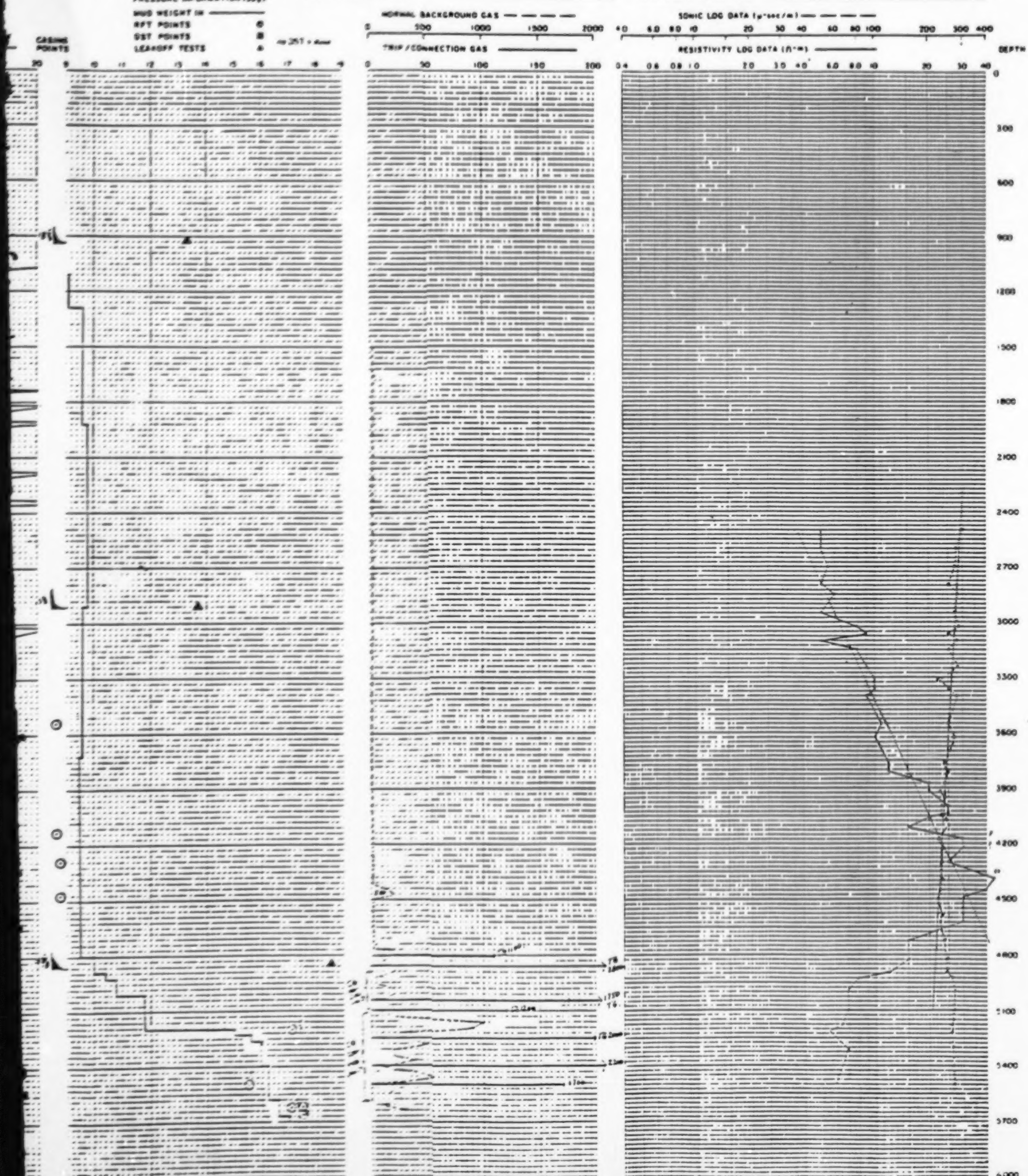
PRESSURE EVALUATION LOG

SCOTIAN SHELF GEOPRESSURE EVALUATION
PROJECT No. 059-2



G

WELL NAME (#14)
RIG NAME
OPERATOR
LOCATION N W
SPUD DATE
COMPLETION DATE
TOTAL DEPTH
WATER DEPTH

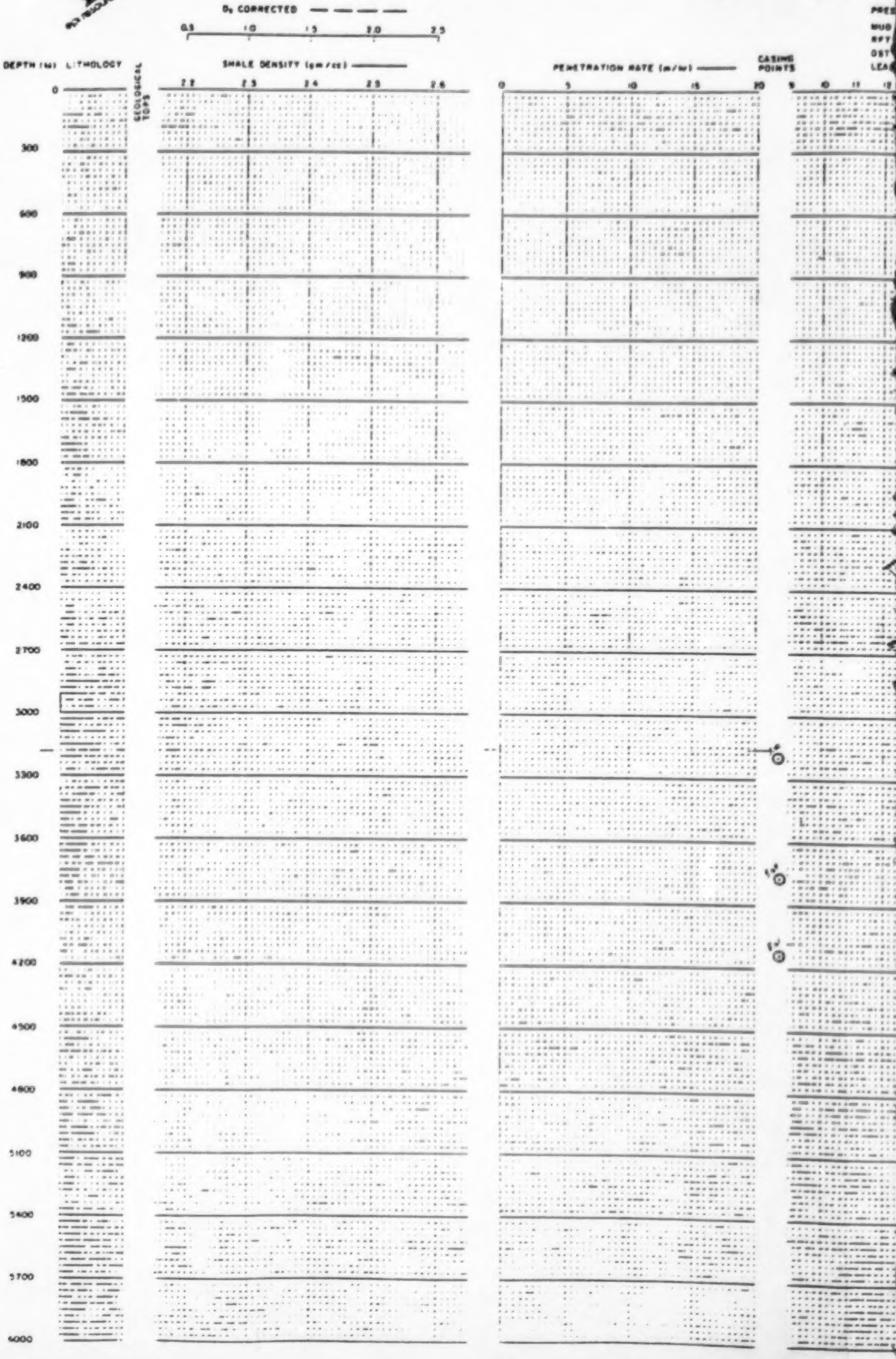


NOTE: PLOT ONLY POINTS FROM WIRELINE LOGS ASSOCIATED WITH SHALES

PRESSURE EVALUATION LOG

SCOTIAN SHELF GEOPRESSURE EVALUATION
PROJECT No. 059-2

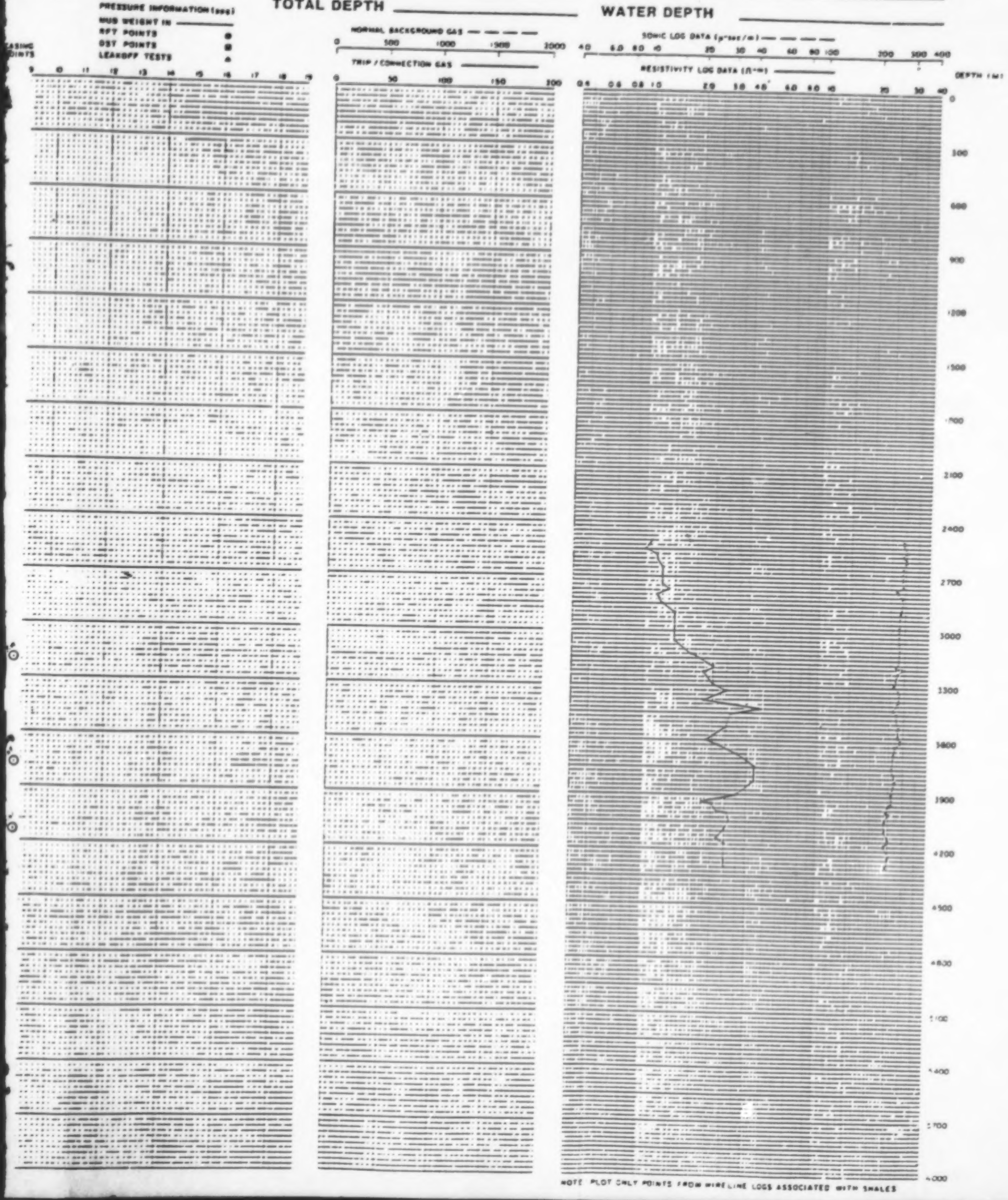
DATA NOT AVAILABLE
AS OF APR 2/86



T AVAILABLE
Apr 2/86

WELL NAME (#15)
OPERATOR
SPUD DATE
TOTAL DEPTH

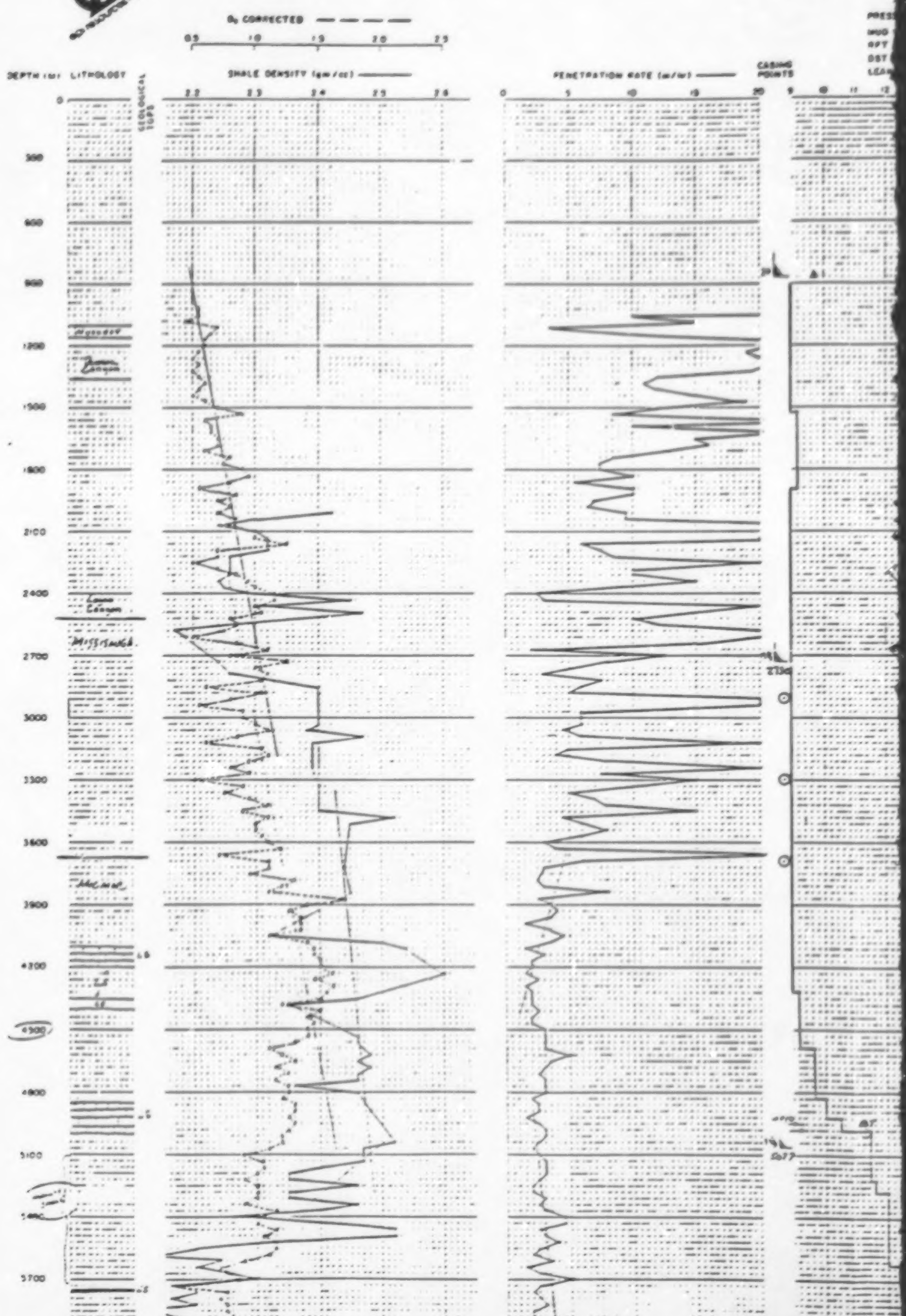
RIG NAME
LOCATION N W
COMPLETION DATE
WATER DEPTH



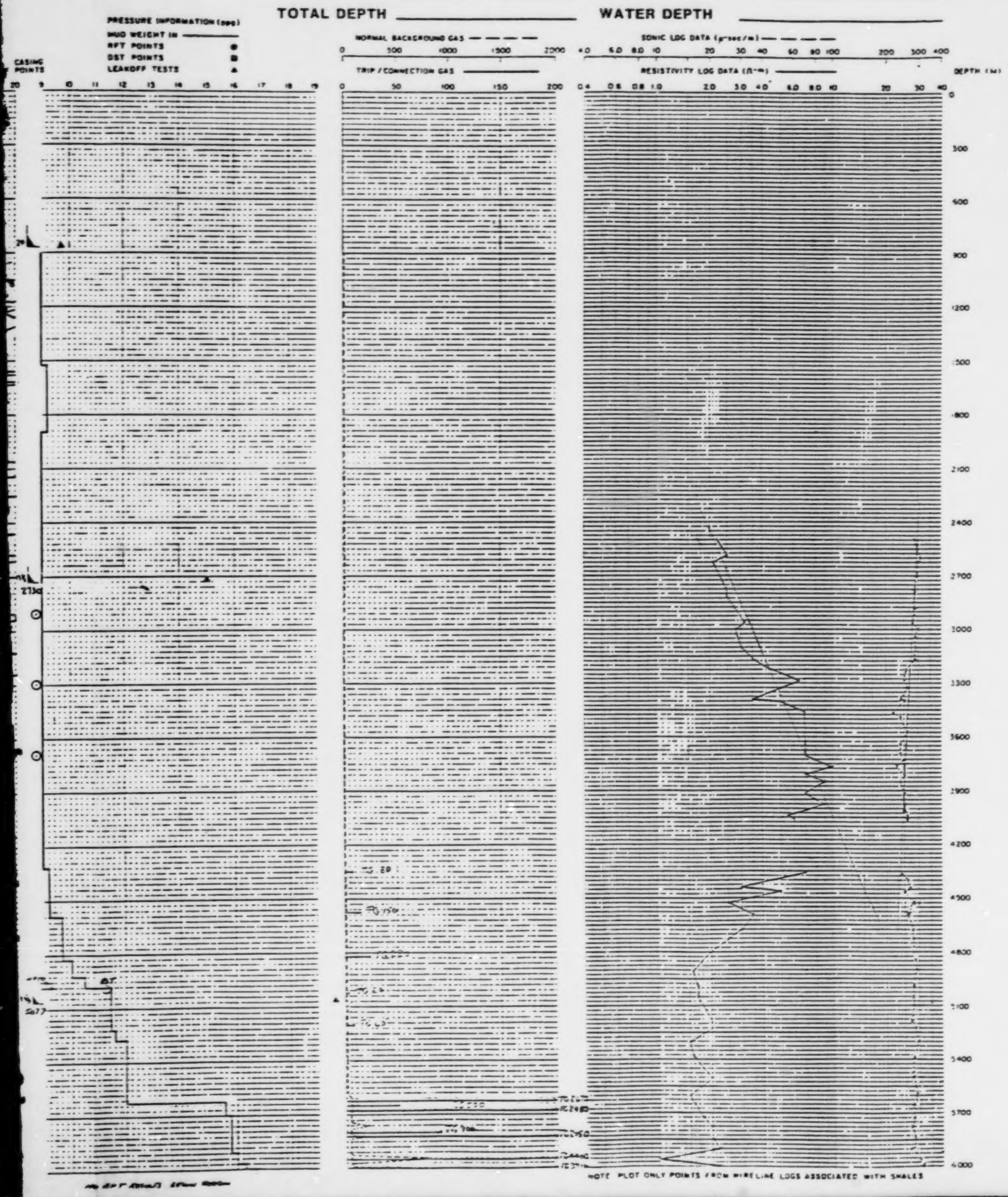
NOTE: PLOT ONLY POINTS FROM WIRELINE LOGS ASSOCIATED WITH SHALES

PRESSURE EVALUATION LOG

SCOTIAN SHELF GEOPRESSURE EVALUATION
PROJECT No. 059-2



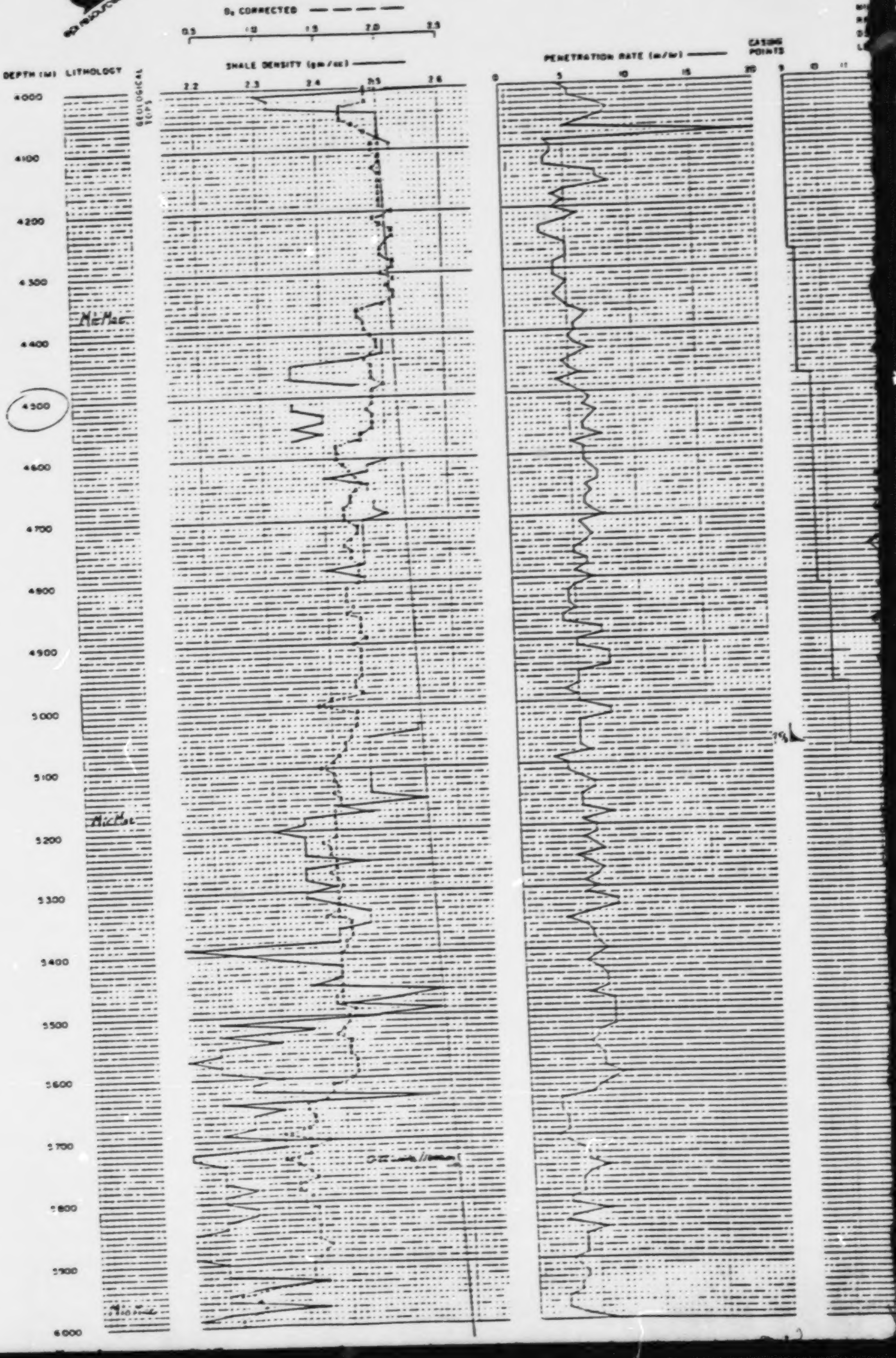
WELL NAME (#16.)
RIG NAME
OPERATOR
LOCATION N W
SPUD DATE
COMPLETION DATE
TOTAL DEPTH
WATER DEPTH



NOTE: PLOT ONLY POINTS FROM WIRELINE LOGS ASSOCIATED WITH SHALES

PRESSURE EVALUATION LOG

SCOTIAN SHELF GEOPRESSURE EVALUATION
PROJECT No. 059-2



WELL NAME (#16. EXPANDED)

OPERATOR ______

SPUD DATE ______

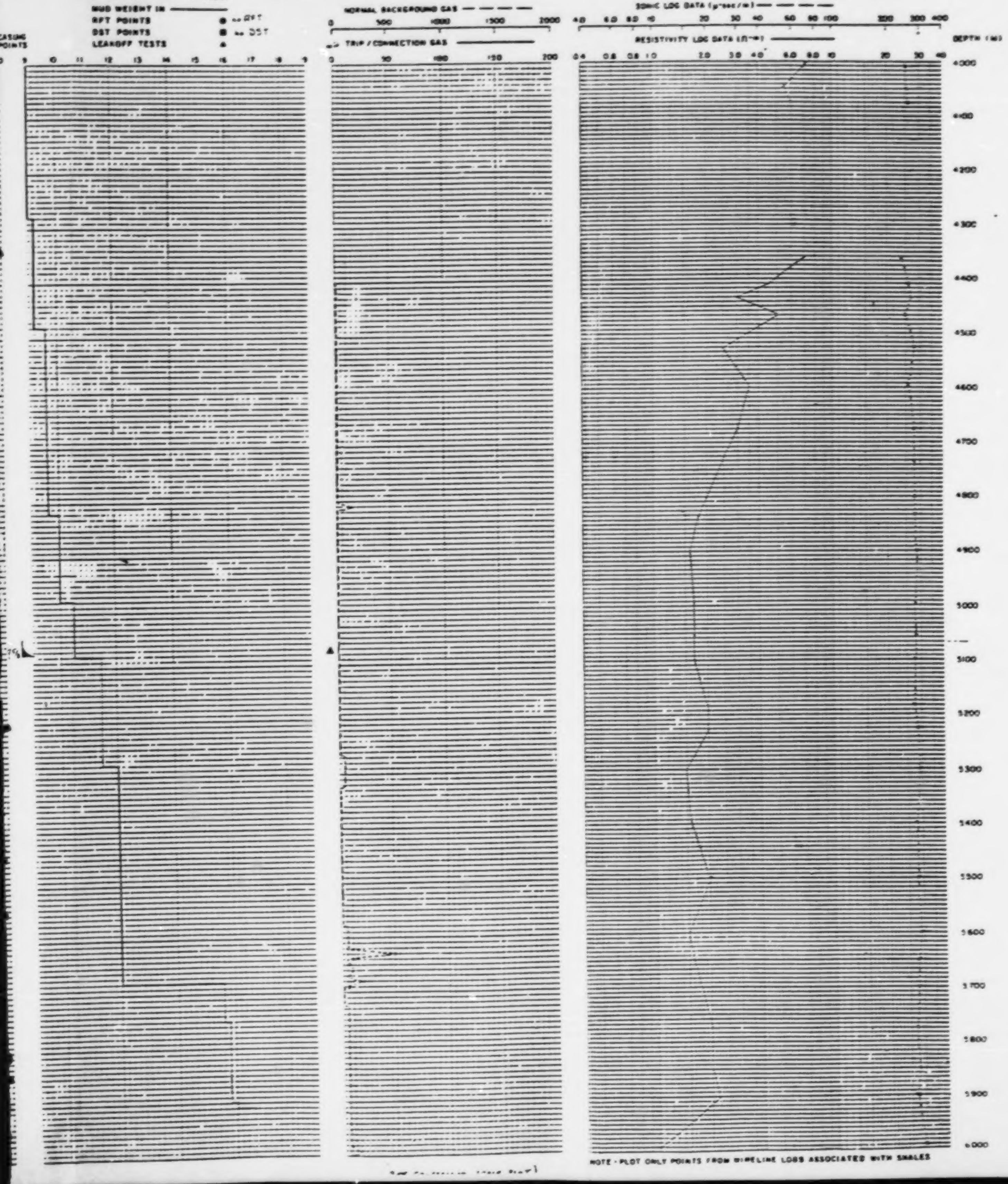
TOTAL DEPTH ______

RIG NAME ______

LOCATION ______ N ______ W

COMPLETION DATE ______

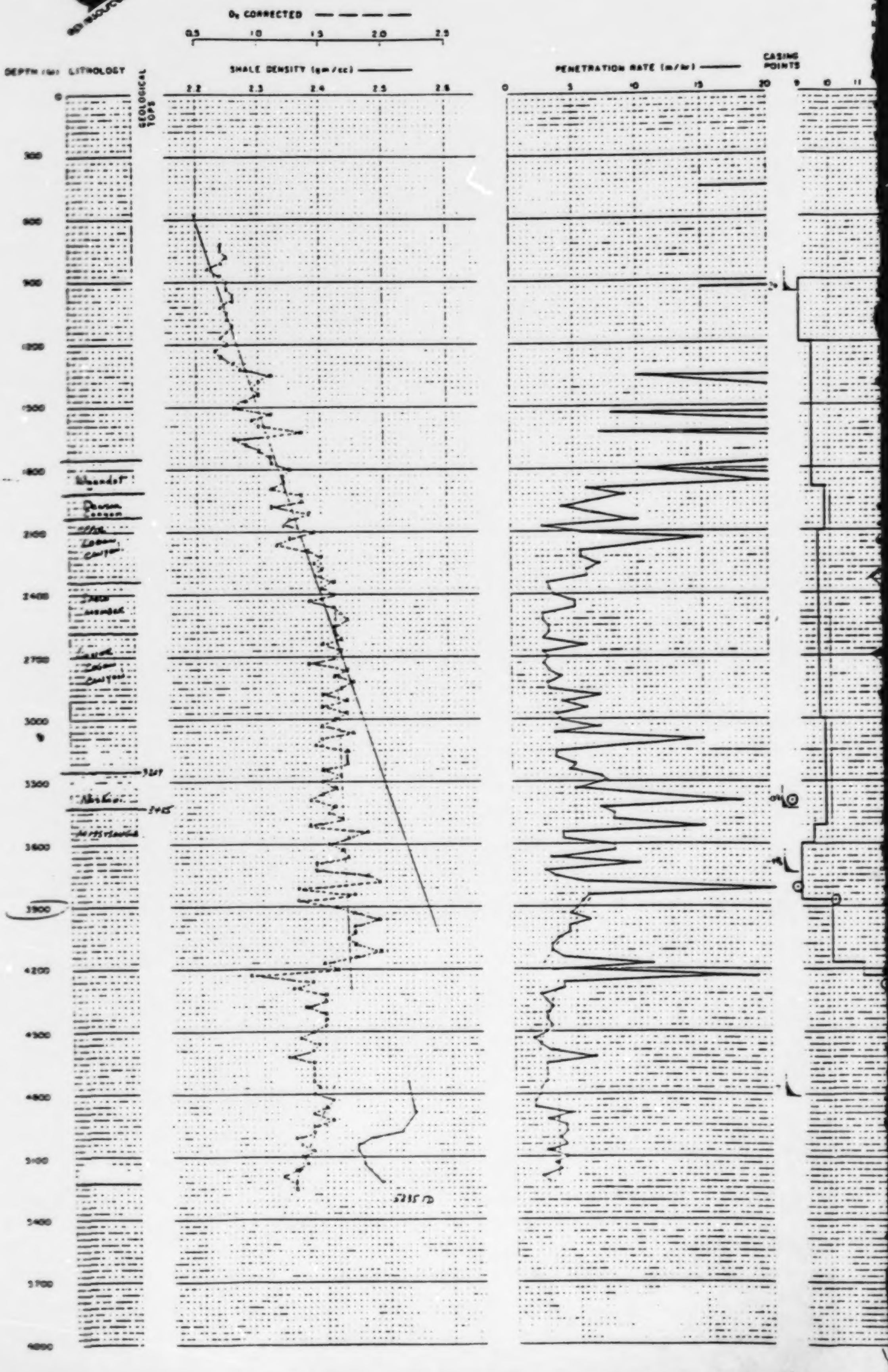
WATER DEPTH ______



NOTE · PLOT ONLY POINTS FROM WIRELINE LOGS ASSOCIATED WITH SHALES

PRESSURE EVALUATION LOG

SCOTIAN SHELF GEOPRESSURE EVALUATION
PROJECT No. 059-2



WELL NAME (#17.)

OPERATOR ______

SPUD DATE ______

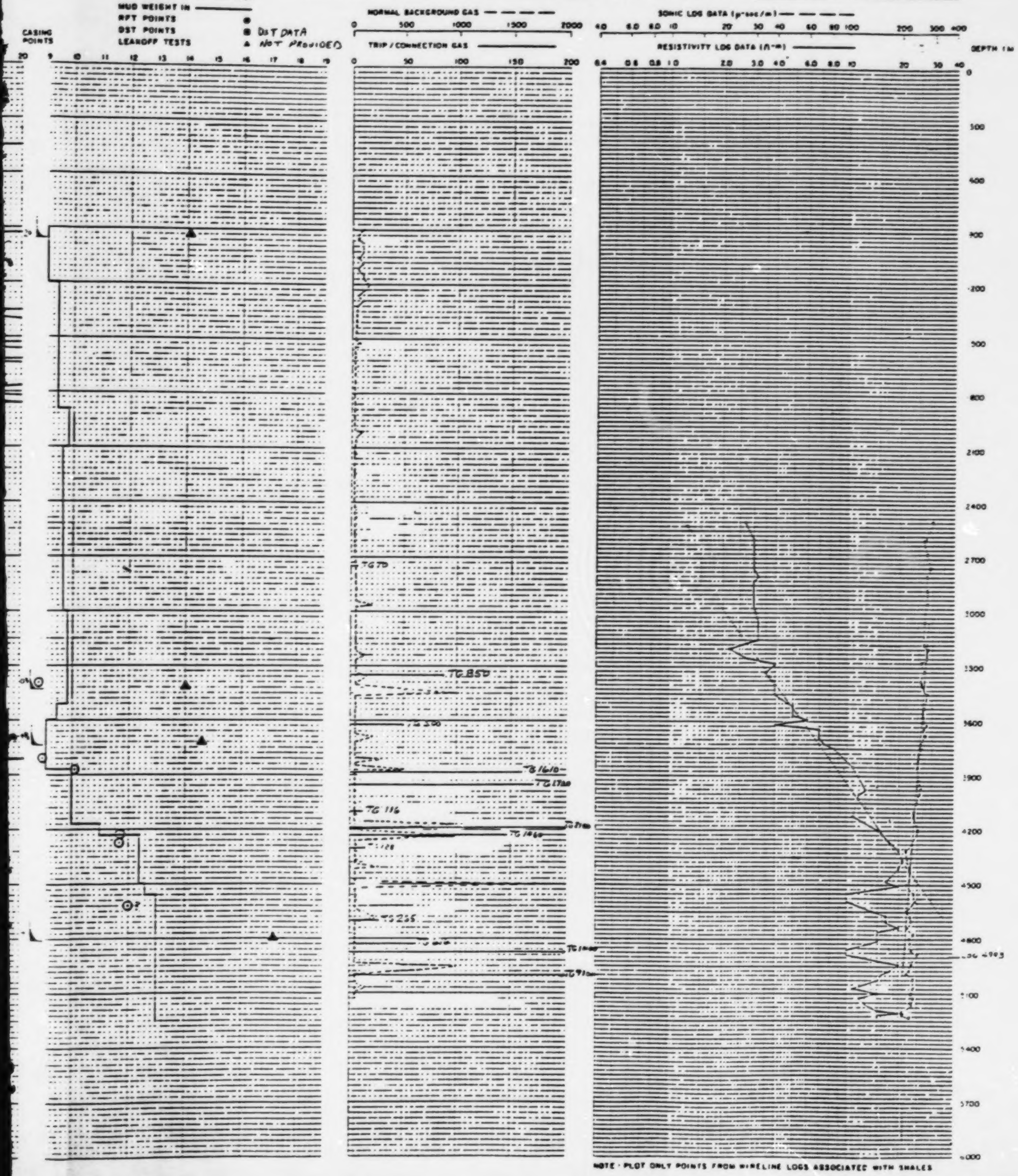
TOTAL DEPTH ______

RIG NAME ______

LOCATION ______ N ______ W

COMPLETION DATE ______

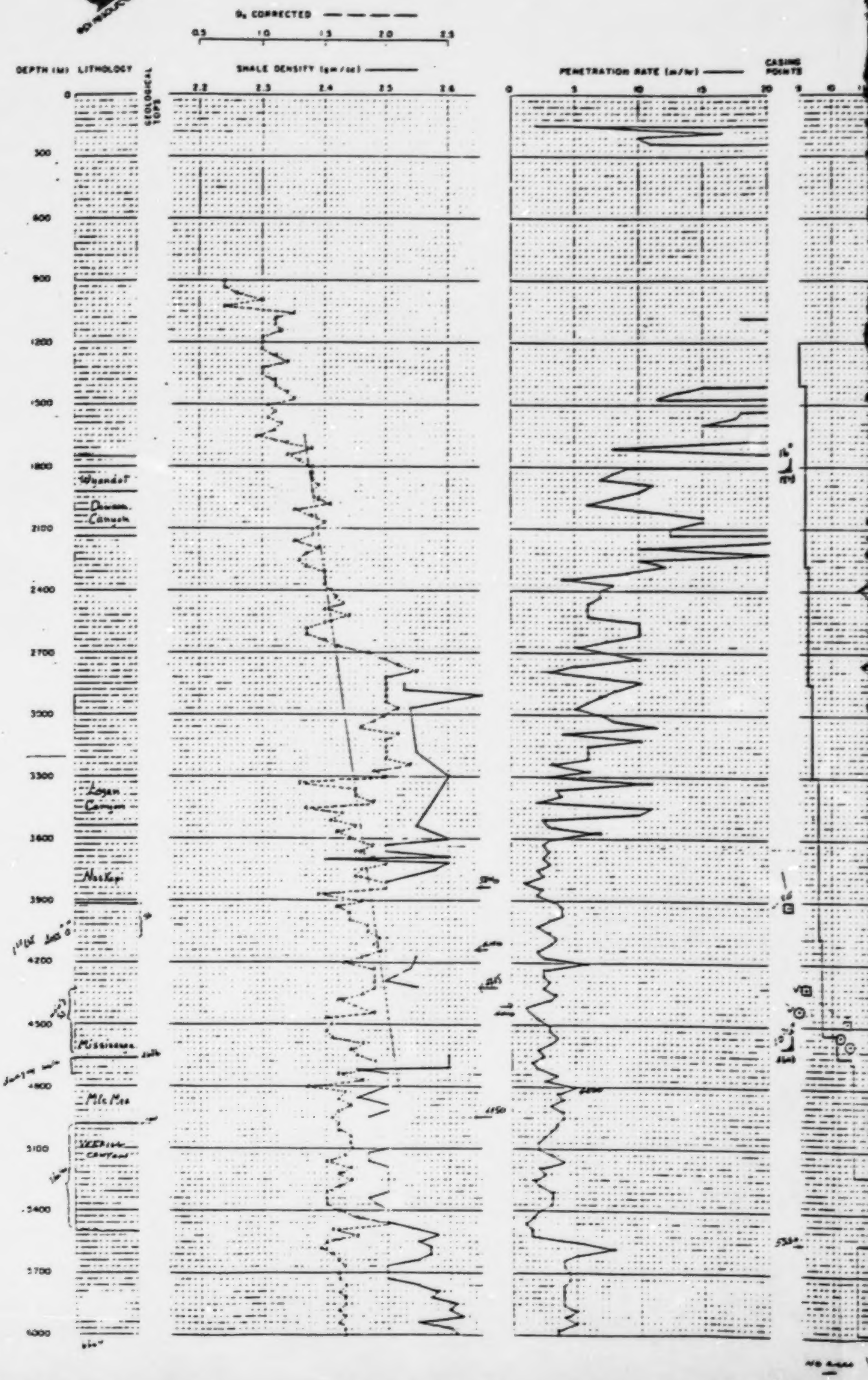
WATER DEPTH ______



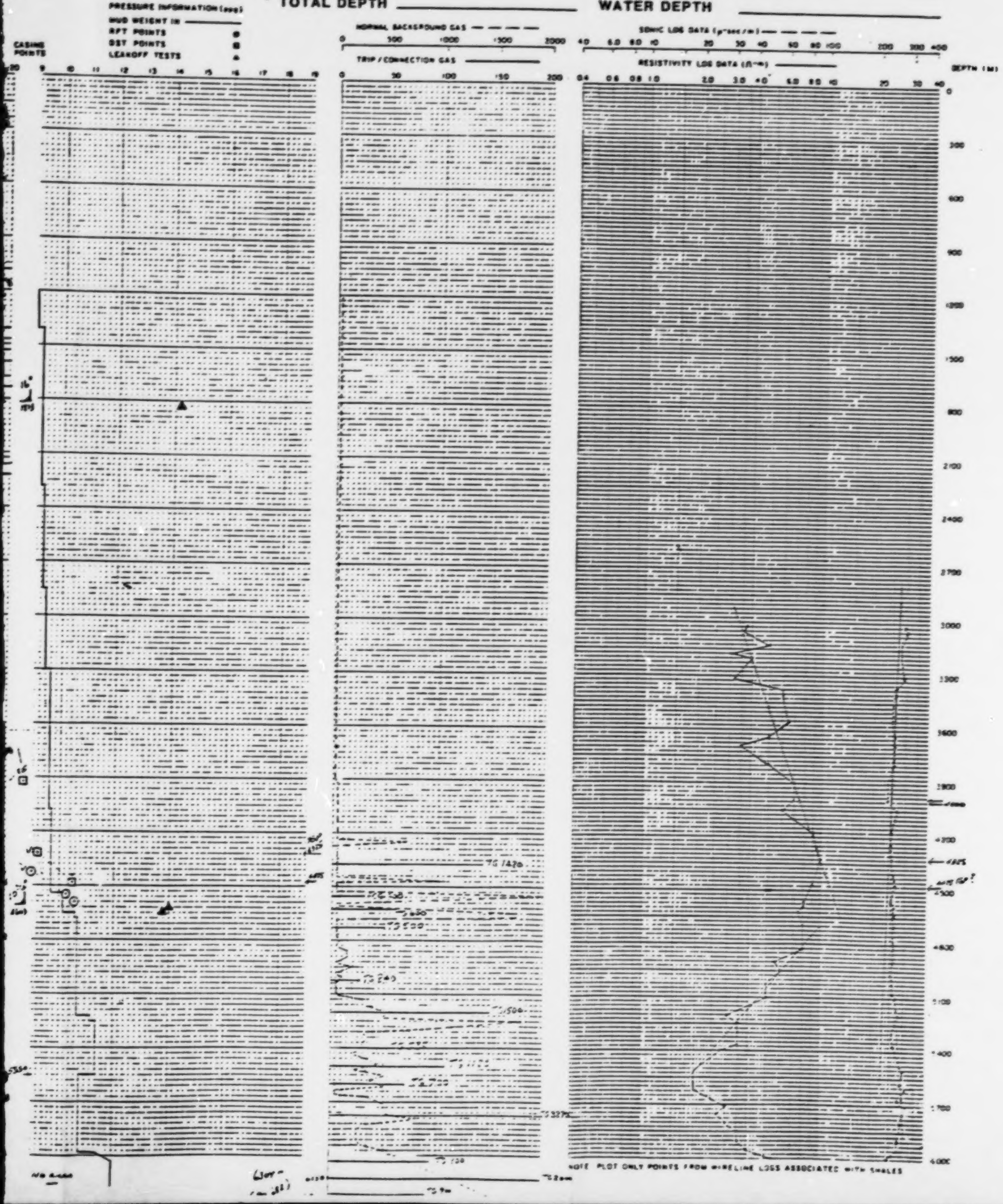
NOTE - PLOT ONLY POINTS FROM WIRELINE LOGS ASSOCIATED WITH SHALES

PRESSURE EVALUATION LOG

SCOTIAN SHELF GEOPRESSURE EVALUATION
PROJECT No. 059-2



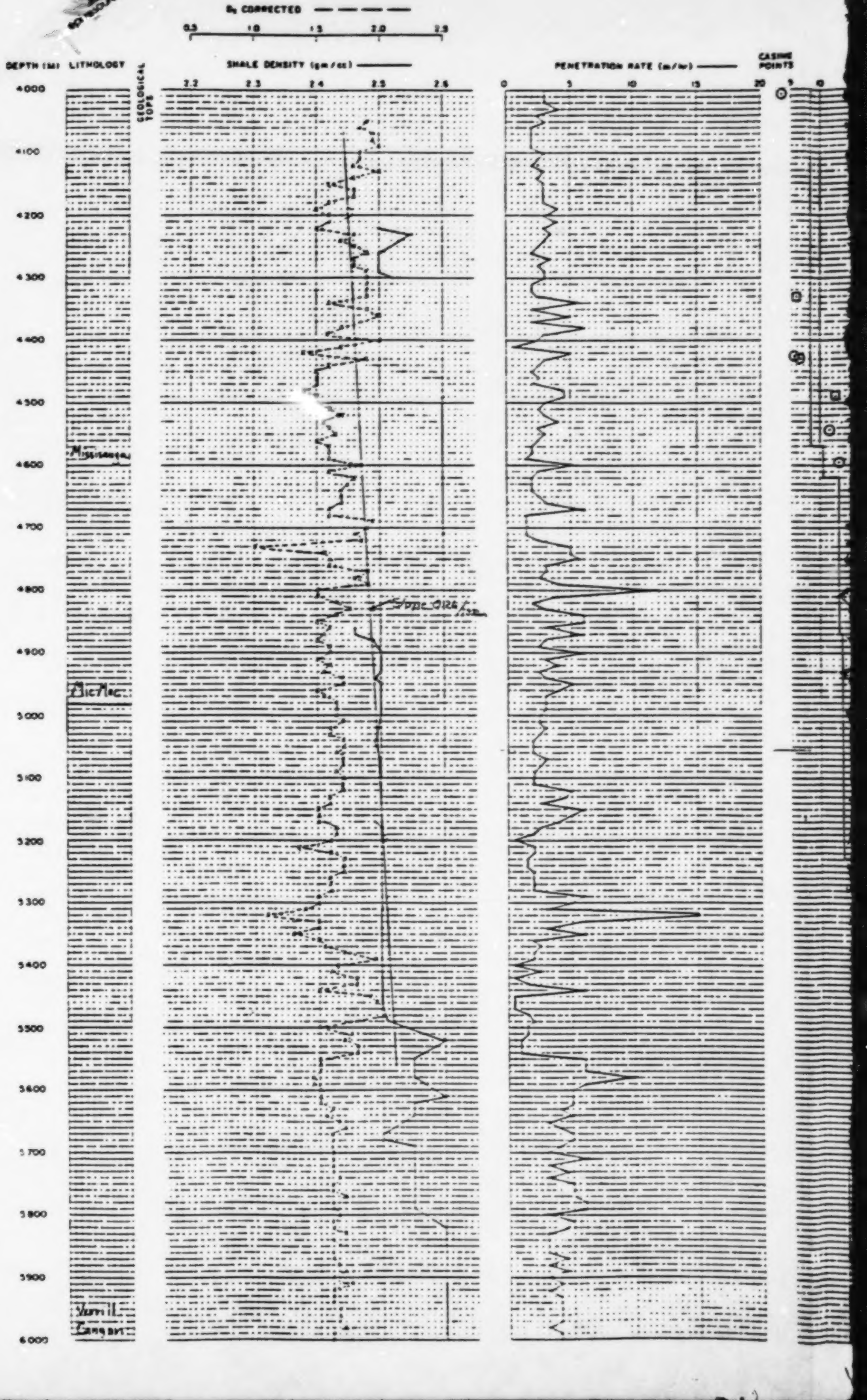
WELL NAME (#18.)
RIG NAME
OPERATOR
LOCATION ____ **N** ____ **W** 113.
SPUD DATE
COMPLETION DATE
TOTAL DEPTH
WATER DEPTH



NOTE PLOT ONLY POINTS FROM WIRELINE LOGS ASSOCIATED WITH SHALES

PRESSURE EVALUATION LOG

SCOTIAN SHELF GEOPRESSURE EVALUATION
PROJECT No. 059-2



G

WELL NAME (#18. Elwood)

OPERATOR

SPUD DATE

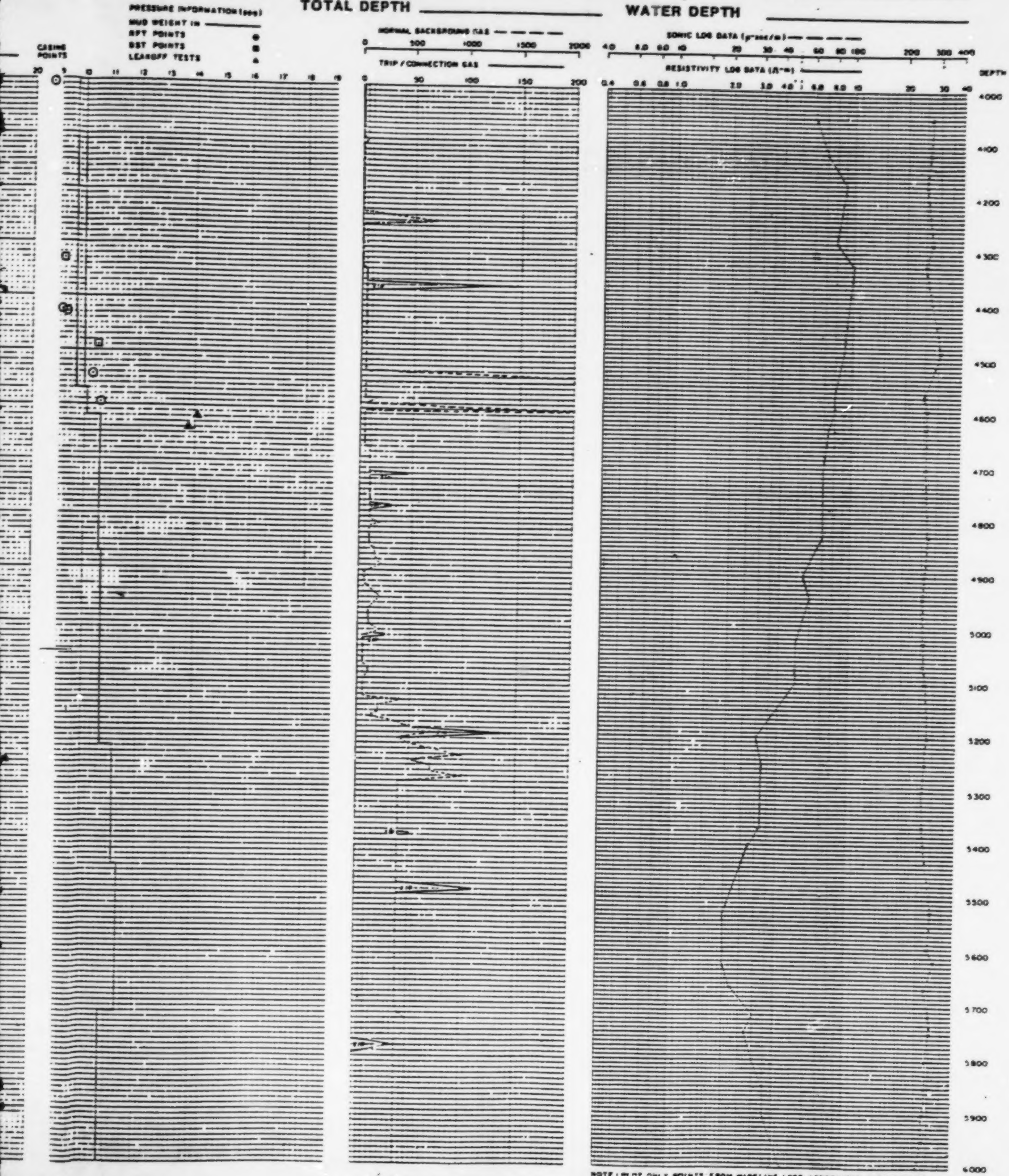
TOTAL DEPTH

RIG NAME

LOCATION N W

COMPLETION DATE

WATER DEPTH

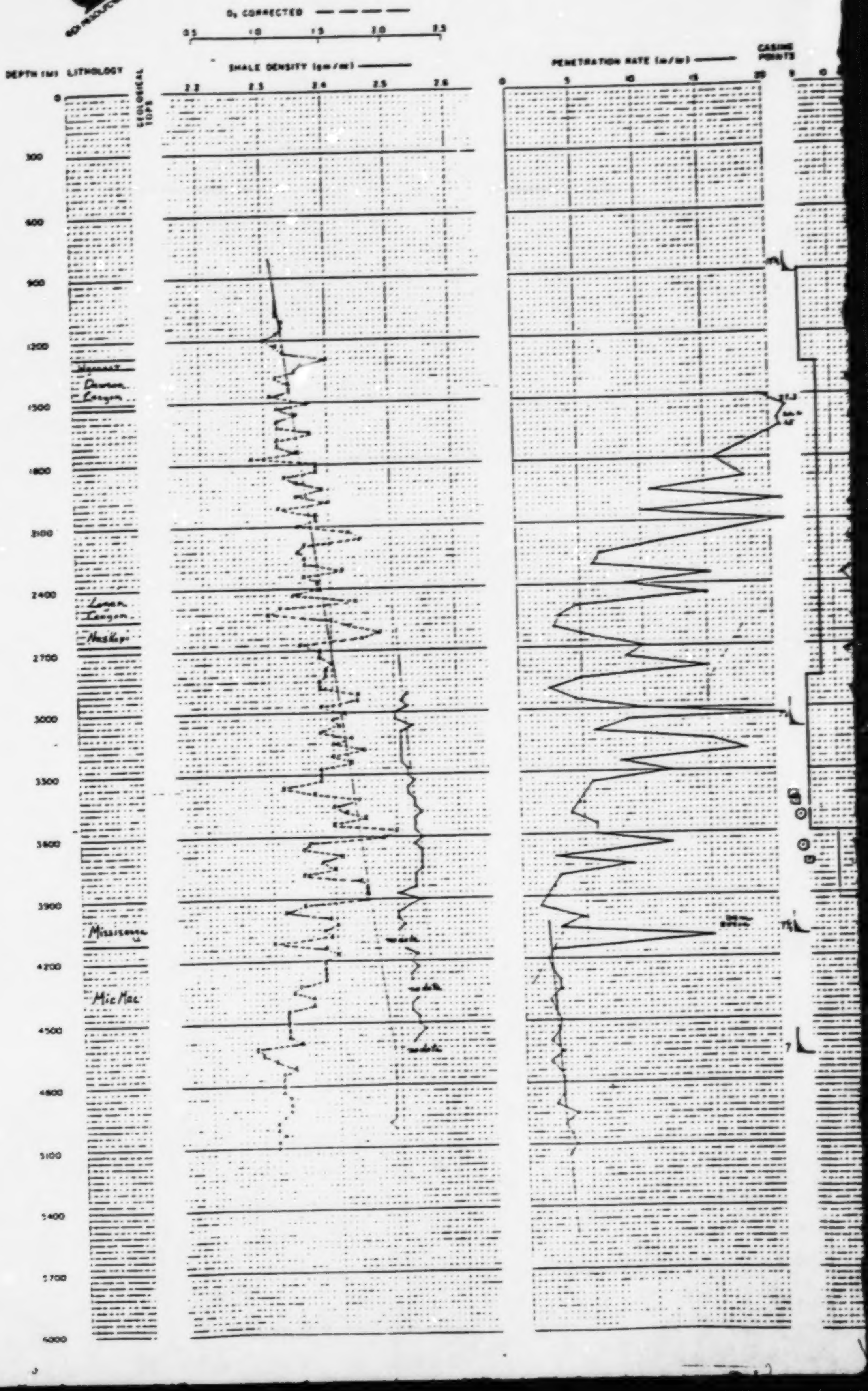


Range is Compressed Scale
Ref 1

NOTE: PLOT ONLY POINTS FROM WIRELINE LOGS ASSOCIATED WITH SHALES

PRESSURE EVALUATION LOG

SCOTIAN SHELF GEOPRESSURE EVALUATION
PROJECT No.059-2



G

WELL NAME 1 F19.

OPERATOR ____

SPUD DATE ____

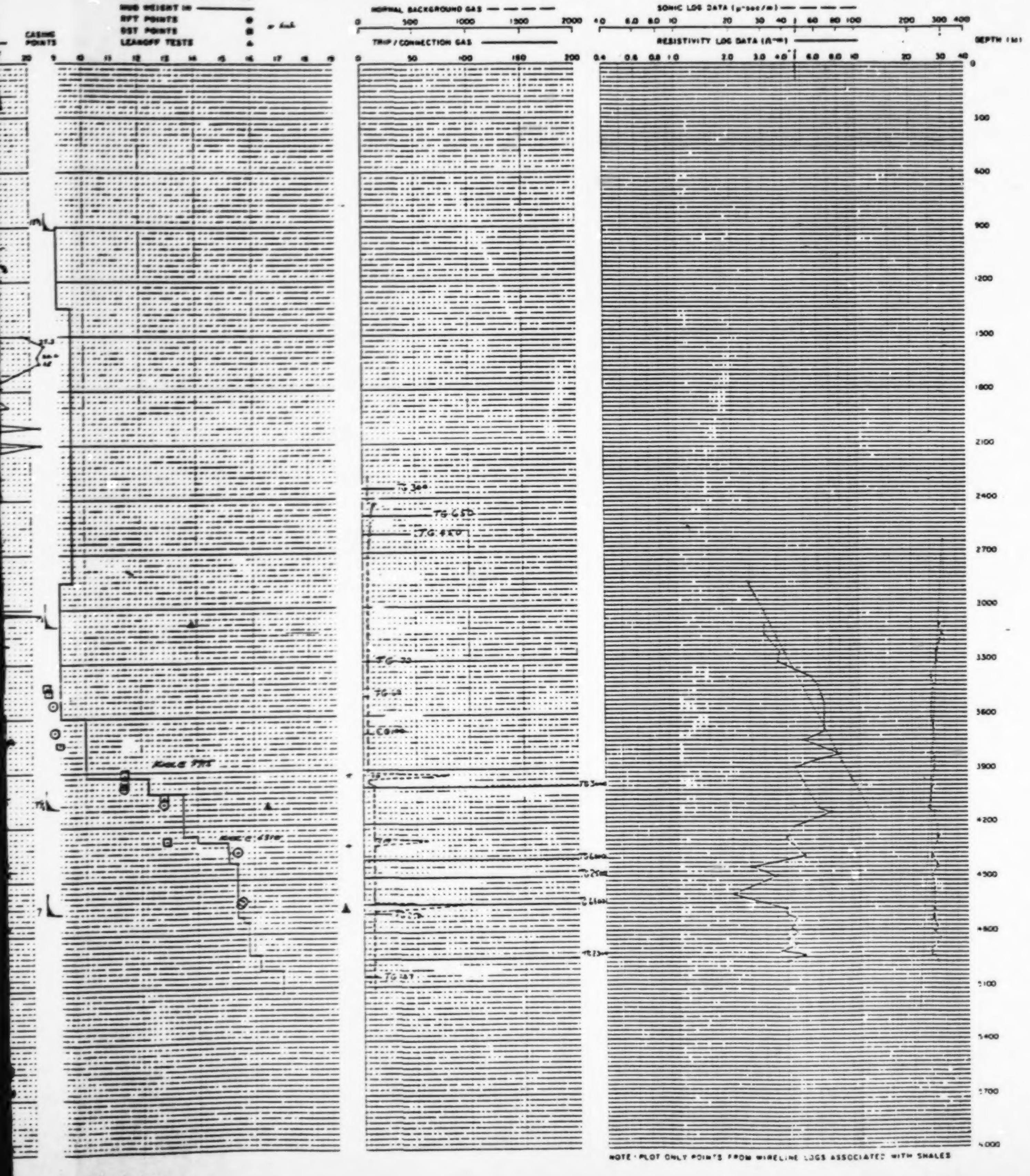
TOTAL DEPTH ____

RIG NAME ____

LOCATION ____ N ____ W

COMPLETION DATE ____

WATER DEPTH ____



NOTE: PLOT ONLY POINTS FROM WIRELINE LOGS ASSOCIATED WITH SHALES

COMBINED EFFECTIVENESS OF 5 PARAMETERS

Well #	D Exponent	Trip Gas	E Logs	ROP	SH Density	Detectable?
1	Poor	Good	Good	0	0	Yes
2	Poor	0	0	0	Fair	Yes
3	0	Good	0	0	0	Yes
4	Good	Good	0	0	0	Yes
5	Fair	0	0	0	0	No
6	Fair	0	0	0	0	No
7	0	Good	Fair	Fair	0	Yes
8	Good	Good	Good	0	0	Yes
9	0	Good	0	Poor	0	Yes
10	0	Good	0	0	Poor	Yes
11	Fair	Good	Poor	0	0	Yes
12	Poor	Good	Poor	0	0	Yes
13	Fair	Good	Good	Poor	Good	Yes
14	Fair	Good	Good	Fair	0	Yes
15						
16	Fair	Poor	Fair	0	Poor	Yes
17	0	Poor	0	0	0	No
18	Poor	Poor	0	0	0	No
19	Poor	Poor	0	0	Poor	Yes

Shale Density

Well #	Indicator	Distance Above Kick	Comments
1	None	-	Too much data scatter to establish a trend
2	Fair	150 m	Shale density shifts noticeably
3	None	-	Insufficient data uphole to establish a "normal" trend
4	None	-	No data provided
5	None	-	Large data scatter
6	None	-	Shale density decrease occurs after drilling into pressure
7	None	-	Only occasional data
8	None	-	A shale density trend can be developed in upper "normal" section, but large data scatter hides any change in trend through the transition zone
9	None	-	Insufficient data
10	Poor	80 m	Change in trend is difficult to recognize due to data scatter
11	None	-	Insufficient data and large scatter
12	None	-	No data
13	Good	750 m	Shale density has a noticeable shift to the left prior to the kick
14	None	-	No data provided
15	-	-	No data available
16	Poor	400 m	Large data scatter
17	None	-	Insufficient data
18	None	-	Data is infrequent and values too scattered to establish a trend
19	Poor	100 m	Change in slope of shale density plot is very slight and occurs too close to the first kick to be recognized

D Exponent

Well #	Indicator	Distance Above Kick	Comments
1	Poor	300 m	D Exp. shows shift to left initially then reverts to normal trend line prior to kick
2	Poor	160 m	D Exp. shift is obscured by data scatter
3	None	-	D Exp. shifts to left 600 m above kick but resumes a normal gradient. Below kick, D Exp. shows a recognizable leftward trend
4	Good	150 m	D Exp. shows a consistent shift to the left 150 m prior to kick
5	Fair	200 m	When D Exp. slope is carried onto expanded scale, a fairly obvious change in slope occurs at 4300 m
6	Fair	500 m	D Exp. has trends to the left of the "normal" line starting 500 m above the pressured zone
7	None	-	D Exp. shift becomes obvious only after the kick
8	Good	1100 m	D Exp. shift is gradual but starts well above the depth where pressure was encountered
9	None	-	Shift D Exp. occurs too late to be recognized prior to the kick
10	None	-	Large data scatter prevents recognition of D Exp. shift in time to warn of the kick
11	Fair	200 m	D Exp. trends to the left of the "normal" line fairly consistently over 200m
12	Poor	100 m	D Exp. shift is slight. Distance too short to place much confidence in D Exp.
13	Fair	700 m	A trend change in D Exp. is observed well before the kick
14	Fair	400 m	A D Exp. shift is noticeable below the 9-5/8 shoe
15	-	-	No data available
16	Fair	1000 m	A slope change is noticeable in D Exp.
17	None	-	D Exp. changes slope well above the transition zone.The shift in D Exp. occurs too late to indicate the pressure
18	Poor	100 m	D Exp. has a small change in slope, but would be difficult to recognize with the data scatter
19	Poor	300 m	D Exp. change is gradual and data scatter masks the change in slope

Penetration Rate

Well #	Indicator	Distance Above Kick	Comments
1	None	-	Large data scatter
2	None	-	Possibly a slight increasing trend is there, but is hidden by data scatter
3	None	-	ROP continues slight decrease into the pressure
4	None	-	ROP decreases into the pressure
5	None	-	Data scatter makes it impossible to establish a trend
6	None	-	ROP appears to decrease while drilling into the pressure
7	Fair	400 m	An increasing ROP trend is noticeable 400 m above the kick
8	None	-	There are no noticeable trend changes in ROP
9	Poor	200 m	A slight increase in ROP trend starts 200 m above the kick
10	None	-	Large data scatter makes it difficult to see any trends
11	None	-	ROP decreases just before the kick
12	None	-	No noticeable change in ROP trend
13	Poor	150 m	A slight increase in ROP is present
14	Fair	200 m	ROP increases prior to drilling into the pressure increase
15	-	-	No data available
16	None	-	No observed change in ROP trend
17	None	-	Data scatter hides any trend changes
18	None	-	ROP decreases with depth
19	None	-	Too much data scatter

Connection/Trip Gas

Well #	Indicator	Distance Above Kick	Comments
1	Good	600 m	High TG 700 over 100 background on two bit trips last trip before kick showed 2600 units
2	None	-	High background gas levels masked trip and connection gas
3	Good	400 m	Significant levels of trip gas
4	None	500 m	Low background gas permitted detection of trip gas increases prior to the kick
5	None	-	Trip gas appears to decrease as the kick approaches
6	None	-	Trip gas actually decreases just before drilling into pressure
7	Good	900 m	Connection and trip gas increased steadily down to kick depth
8	Good	1100 m	Very high connection and trip gas indicated an under-balanced condition
9	Good	600 m	Trip gas and connection gas increase as drilling approaches the kick. Especially noticeable with very low background gas
10	Good	120 m	Trip gas increased dramatically 120 m above kick
11	Good	400 m	Increasing trip gas provides a good indicator of top of transition zone
12	Good	150 m	High trip gas indicates underbalance condition prior to kick
13	Good	800 m	Underbalance condition was indicated by high trip gas readings
14	Good	600 m	Trip and connection gas readings increase as the transition zone is drilled
15	-	-	No data available
16	Poor	1000 m	Only slight increase in trip gas is observed prior to kick
17	Poor	300 m	Trip gas tends to increase only after a higher pressure section is penetrated
18	Poor	75 m	One trip gas reading leads up to the pressure increase
19	Poor	200 m	Small increase in connection gas leading up to first kick

E Logs

Well #	Indicator	Distance Above Kick	Comments
1	Good	700 m	Good change in resistivity trend. Subtle change in ITT trend. Logging run at 4302 m provided a 30 m warning
2	None	-	Resistivity and ITT both shift 200 m above the kick, but logs were not run until after the kick
3	None	-	Trend change in resistivity and ITT do not occur until into the pressure
4	None	-	Resistivity and ITT show a trend change 150 m above kick, but logging runs were not scheduled so as to be useable as a warning
5	None	-	Resistivity and ITT plot indicate pressure start 150 m above kick. Logging program did not include a run at an appropriate depth
6	None	-	Data gaps in ITT. Resistivity indicates top of pressure at 4300 log depth was 4803, after drilling into pressure
7	Fair	400 m	Logging at 4805 showed a good shift in resistivity and a minor change in ITT trend
8	Good	1500 m	Logs at 4670 m were deep enough to show a trend reversal on resistivity and ITT
9	None	-	Logs at 4925 did not show enough of a trend reversed to be recognized
10	None	-	No logs were run prior to the kick. The resistivity and ITT plot both indicate the top of the transition zone 300 m above the kick
11	Poor	200 m	Logs of 9-5/8 depth showed the first part of the trend change for both resistivity and ITT
12	Poor	300 m	Considerable data scatter on both resistivity and ITT could lead to an inter pretation of top of transition zone of 3900 m or at 4550 m
13	Good	800 m	Resistivity curve shows a good trend change 800 m above the kick
14	Good	700 m	Both resistivity and ITT curves show a trend reversal identifiable at the 9-5/8 setting depth
15	-	-	No data available
16	Fair	1000 m	Resistivity curve indicates transition zone 450 m too high ITT plot is fair indicator from logs at 9-5/8 depth
17	None	-	Transition zone full between logging runs. Resistivity and ITT trend changes occur deeper than the RFT confirmed pressures
18	None	-	Resistivity plot indicates a transition zone starting around 4400 m. This was not logged until drilling had passed 4600 m
19	None	-	Resistivity plot changes slope 100 m above first kick logs were run after the kick